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RESEARCH

Sept 26, 1975

CANADIAN UTILITIES LIMITED

(CU - T.S.E.)

Current Price	1975 Price Range	Earnings Per Share(1) 1974	1975E	1976E	Price/Earnings 1974	1975E	1976E	Ind. Div.	Yield
$9.00	$9 7/8-$7 5/8	$1.05	$1.35	$1.50	8.6	6.7	6.0	$0.74	8.2%

(1) Fully-diluted operating earnings.

SUMMARY AND CONCLUSION

1973-1974 Results — CU's earnings reached a peak in 1972, the first full year of operations following the corporate restructuring that became effective January 5, 1972. Net income remained approximately at the 1972 level throughout 1973 and 1974 although substantial plant expansion and growth in the number of customers took place. During these years, strong inflationary trends in operating costs and rapidly rising interest expenses prevented the Company's electric and gas subsidiaries from earning their full allowable returns.

1975 Outlook — In the first half of 1975, consolidated earnings again approximated first half 1974 results. A much stronger trend is expected for the second half of 1975, reflecting continued growth in operations as well as the benefits of rate increases granted this year, which are designed to provide an adequate return on equity for the full year. While the rate increases initially are effective on an interim basis, the 1975 earnings forecast assumes that the increases subsequently will be confirmed as has been the case in the past.

1976 Outlook — In 1976, rate increases granted during the second half of 1975 will be in effect for a full year and will be applied to larger rate bases. With respect to the 1976 earnings forecast, it is assumed that additional rate increases will be allowed should they be required to maintain return on common equity at the levels granted in the recent decisions.

Long-Term Benefits In Alberta

The fact that CU's operations are concentrated in Alberta has a number of advantages from an investment standpoint when CU is compared with alternative utility investments in other provinces.

Ample Energy Supplies: Alberta has plentiful supplies of coal, which are used for electric power generation and will likely be used in coal gasification in the future. With respect to natural gas supplies, the Province's policy is to set aside sufficient reserves to protect Alberta's projected requirements for thirty years. Furthermore, the local gas utilities have priority rights on all gas leaving the Province.

Strong Industrial Growth: Given the importance that industries place on security of long-term energy supplies, Alberta's favourable energy resource position has attracted large scale industrial development in the Province. The industrial expansion and accompanying demand for manpower will ensure substantial economic growth in Alberta for many years.

Rapid Utility Rate Base Expansion: As a result of the strong economic growth in Alberta, provincial demand for basic utility services, i.e., electric power and natural gas, is expected to increase at a rate significantly higher than the national average. Electric energy requirements in Alberta are projected to rise at a compound annual rate of 13% over the next five years compared to growth of 7 1/2% anticipated for all of Canada. During the same period, natural gas consumption is forecast to rise approximately 8 1/2% annually in Alberta, while there will likely be minimal growth in other provinces due to the limited availability of new supplies. Consequently, the Alberta-based utilities will continue to engage in substantial plant expansion, rapidly increasing the rate bases to which earnings are related. Inflationary trends in construction costs and required installations of expensive anti-pollution equipment for electric utilities will further accelerate rate base growth.

Favourable Regulatory Environment: The approach to regulation adopted by the Public Utilities Board of Alberta is responsive to the particular difficulties faced by utilities in a period of rapid inflation and high interest rates. Regulatory lag has been minimized through the Board's practice of granting interim rate increases shortly after the filing of applications and its willingness to use future test years to establish revenue requirements. The Board's rulings have also allowed rate structures that provide for satisfactory returns on common equity, which should enable the utilities to raise additional equity capital without creating dilution. Allowable returns on common equity are generally around 15%, a level that should be sufficient to maintain market prices above book value per share. It is noteworthy also that the Public Utilities Board of Alberta recently invited specific proposals to assist the Board in structuring utility rates in ways that can protect shareholders against erosion of earnings due to inflation.

The Company's Improving Position

In addition to the factors mentioned above, the following developments have positive investment implications for CU's securities:

Stronger Common Equity Base: The common equity portion of CU's capitalization will be significantly strengthened by the expected conversion into common stock of all or most of the $34.3 million $1.25 convertible preferred shares as a consequence of the recent increase in the dividend rate on the common stock. Additional equity capital will be added with the proposed common equity issue this fall and the proposed sale of certain assets.

Higher Interest Coverage: Further upgrading of the investment quality of CU's securities will result from contemplated changes in accounting methods relating to depreciation charges and income taxes, which will lead to significantly higher debt interest coverages.

Improved Marketability: The marketability of CU common shares will increase materially as a result of conversions and the proposed new financing. The number of common shares held by investors, excluding those owned by the parent company, is estimated to almost triple this year, from 1.3 million shares to approximately 3.9 million shares.

Recommendation

On a fully-diluted basis, CU's operating earnings are estimated to rise from $1.05 per share in 1974 to $1.35 in 1975, an increase of 29%. In 1976, a further 11% increase to $1.50 per share is anticipated. While this high rate of growth partly reflects the recovery from slow growth in 1973 and 1974 and is not expected to be sustained over the longer term, it appears reasonable to expect an average longer-term growth rate in earnings per share of approximately 7% annually. Thus, given the current dividend yield of 8.1%, CU common offers prospects for an overall annual return of approximately 15%. CU common shares are recommended as an attractive investment alternative to bonds and most other Canadian utility stocks.

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SEPTEMBER 26, 1975
MONTREAL, QUEBEC

OPERATING ENVIRONMENT

Being an Alberta-based utility, Canadian Utilities Limited (CU) operates within an exceptionally favourable environment for three fundamental reasons: secure long-term energy supplies, strong economic growth, and a regulatory climate that is responsive to their special needs during a period of inflation and high interest rates. In addition, Alberta's system of rebating federal income taxes and sheltering gas consumers from the full impact of rising wellhead prices have favourable implications.

Ample Energy Supplies

The figures in the table below, which were prepared on the basis of statistics and forecasts developed by the Energy Resources Conservation Board of Alberta ("ERCB"), illustrate the Province's unique energy resource position.

ALBERTA ENERGY RESOURCE RESERVES AND REQUIREMENTS

	Proved Remaining Recoverable Reserves (December 31, 1974)	Alberta 30-Year Requirements (1975-2004)
Conventional Crude Oil and Liquids	8.3 billion barrels)	- 6.2 billion barrels
Synthetic Oil (Oil Sands)	26.5 billion barrels)	
Natural Gas	55.0 trillion cubic ft.	19.9 trillion cubic ft.
Coal (December 31, 1972)	5.3 billion tons	1.7 billion tons

Sources: ERCB report 75-18 "Reserves of crude oil, gas, natural gas liquids, and sulphur", December 31, 1974.
ERCB report 74-W "Appendix to Alberta's requirements of energy and energy resources, 1975-2004", March, 1975.

Approximately 2.0 billion barrels of synthetic oil reserves can be allocated to the Great Canadian Oil Sands plant, which is now in production, and the Syncrude plant, which will be in production in 1978. Including these reserves and not allowing for construction of additional synthetic oil plants, Alberta's apparent exportable surplus of oil is approximately 4.1 billion barrels.

Alberta will continue to export substantial volumes of oil and natural gas in order to generate the large revenues obtainable at current prices, finance its ambitious industrial development program and encourage further exploration for oil and gas. Over the longer term, coal will play an increasingly important role in meeting Alberta's total energy resource requirements.

Alberta has plentiful supplies of coal, which are used for electric power generation and will likely be used in coal gasification after the mid-1980s. With respect to natural gas supplies, the Province's policy is to set aside sufficient reserves to protect Alberta's projected requirements for thirty years. Furthermore, the local gas utilities have priority rights on all gas leaving the Province.

Strong Economic Growth

Given the importance that industries place on security of long-term energy supplies, Alberta's favourable energy resource position has paved the way for the large scale industrial developments that are now under way in the Province. The industrial developments and the accompanying demand for manpower will ensure substantial economic growth in Alberta for many years. Consequently, provincial demand for basic utility services is expected to increase

at a higher rate than the national average. According to an ERCB forecast, Alberta's total energy resource requirements in the 1975-1985 period are expected to increase 111% or at an average annual rate of approximately 7.8%.

FORECAST OF ALBERTA TOTAL ELECTRIC AND NON-ELECTRIC ENERGY RESOURCE REQUIREMENTS 1975-1985
(Trillions of Btu)

	Gas	Oil	Coal	Hydro	Other(1)	Total(2)
1975	474	450	108	18	32	1,083
1976	514	532	122	18	34	1,220
1977	601	572	144	18	63	1,397
1978	681	595	158	18	74	1,527
1979	699	620	184	18	99	1,620
1980	714	696	259	18	100	1,786
1981	718	722	280	18	100	1,837
1982	714	749	311	18	135	1,928
1983	715	778	337	18	136	1,983
1984	714	808	367	18	136	2,043
1985	710	888	516	36	136	2,287

Source: ERCB report 74-W "Appendix to Alberta's requirements for energy and energy resources, 1975-2004", March, 1975.

Notes: (1) Ethane, butane and propane.
(2) Figures may not total correctly due to rounding.

Coal, which currently satisfies about 10% of total requirements, is forecast to account for over 22% by 1985. During the same period, the share of total requirements met by natural gas is forecast to decrease from approximately 44% in 1975 to 31% in 1985. The share supplied by oil should decrease from 42% to 39%.

The figures above refer to energy resource input. For example, coal used for electric generation is included as a requirement for coal rather than electricity.

The following table shows a forecast of Alberta's electric requirements over the next 10 years and indicates the specific areas of growth.

FORECAST OF ALBERTA ELECTRIC ENERGY REQUIREMENTS 1975-1985
(Gigawatt hours)

	Residential & Commercial	Oil Sands	Petrochemical	Other	Total	Transportation	Total(1)
1975	7,960	670	660	4,420	5,750	2,630	16,340
1976	8,710	710	720	4,950	6,380	2,930	18,020
1977	9,510	750	1,520	5,540	7,810	3,250	20,570
1978	10,360	1,240	1,520	6,210	8,970	3,440	22,760
1979	11,320	1,740	2,470	6,950	11,160	3,670	26,150
1980	12,380	2,900	3,040	7,790	13,730	3,890	30,000
1981	13,520	3,280	3,080	8,570	14,930	4,060	32,500
1982	14,720	4,070	3,610	9,420	17,110	4,280	36,100
1983	16,011	5,390	3,610	10,370	19,370	4,430	39,810
1984	17,370	6,110	3,610	11,400	21,120	4,720	43,220
1985	18,820	7,220	3,970	12,540	24,010	5,340	48,160

Source: ERCB report 74-W, March, 1975.
Note: (1) Figures may not total correctly due to rounding.

These forecasts indicate growth in Alberta's total electric energy requirements of nearly 13% annually over the five years 1975 - 1980 (7.5% on a national basis) and approximately 11.5% annually for the ten-year period 1975 - 1985. The growth in projected requirements for oil sands developments is particularly large, with demand in this sector accounting for approximately 15% of total 1985 forecast requirements. If the oil sands were entirely excluded, the annual growth rate in all other areas would be 11.6% in the 1975 - 1980 period and 10.1% in the ten-year period 1975 - 1985.

The following table summarizes the ERCB's forecasts of Alberta's natural gas requirements from 1975 to 1985, broken down by major sectors of the economy.

FORECAST OF ALBERTA GAS REQUIREMENTS 1975-1985

	1975	1980	1985
	(Billions of cubic feet)		
INDUSTRIAL			
Petrochemical Industry:			
Ethylene Plants	1	32	32
Ethylene Derivative Plants	-	7	8
Ammonia Plants	32	133	127
Ammonia Upgrading	7	21	19
Methanol Plants	7	22	29
Other Petrochemical	14	15	17
Total Petrochemical	61	230	232
Oil Sands	7	26	26
Other Industrial	166	179	173
Total Industrial	234	435	431
RESIDENTIAL AND COMMERCIAL	149	180	206
TRANSPORTATION	41	33	19
ELECTRIC ENERGY REQUIREMENTS	50	68	65
TOTAL REQUIREMENTS	474	716	721

Source: ERCB report, March, 1975.

Alberta's gas requirements are expected to rise at an average rate of approximately 8.5% annually from 1975 to 1980, while there will likely be little or no growth in other provinces due to the extremely limited availability of new supplies. While the above forecast suggests that there will be virtually no growth in total gas demand between 1980 and 1985, the actual timing of industrial projects currently scheduled for completion by 1980 could alter growth rates in both five-year periods. The ten-year growth rate is forecast at an average 4.5% annually. (See Appendix A for currently projected completion dates.)

As a result of the strong economic growth in Alberta, the Province's utilities will continue to engage in substantial plant expansion, rapidly increasing the rate bases to which earnings are related. Inflationary trends in construction costs and required installations of expensive anti-pollution equipment for electric utilities should further accelerate rate base growth.

Favourable Regulatory Environment

In order to raise the large amounts of new capital needed for expansion and translate rate base growth into per share earnings growth, the utilities require an enlightened regulatory environment. The approach adopted by the Alberta Public Utilities Board recognizes the problems faced by utilities in a period of rapid inflation and high interest rates. The difficult problem of regulatory lag has also been minimized in Alberta through the Public Utilities Board's practice of granting interim rate increases upon application and employing future test years to establish revenue requirements. The Public Utilities Board has consistently followed the practice of granting interim increases to become effective shortly after filings of applications. These interim increases are subject to later refunds to customers should the Board find that the new rates are higher than justified. All increases granted on an interim basis subsequently have been confirmed by the Board's decisions received to date. With respect to the use of a future test year, the Board relies on estimates of revenues and expenses prepared by the utilities, thereby assisting the companies in overcoming the adverse effects of regulatory lag that would result from employing past test year data during a period of rapidly rising costs. The Board also recognizes the importance of maintaining the return on equity at the permitted level after giving effect to increases in equity due to new financing. Thus, in approving the revenue increases needed to provide an adequate return on equity, the Board takes into account financing planned within the period under review.

It is important for utilities requiring common equity financing that market prices of their common shares be maintained above book value per share. It is believed that the Board feels, on the basis of expert testimony submitted to it, that the equity returns of approximately 15% allowed in its 1975 decisions will, in fact, be sufficient to maintain market prices above book value.

Finally, the Board has indicated that it is fully aware of the erosion of shareholders' earnings caused by inflation. In its recent decision for Calgary Power Ltd., the Board invited proposals on how to deal with this problem.

Income Tax Rebate

Under Canadian income tax legislation, 95% of federal income taxes paid by Canadian electric and gas utilities are refunded to the respective provinces in which their earnings are generated. The amounts refunded to the provinces can either be retained by the provinces or rebated to the utility customers. Alberta is the only province that has chosen to rebate federal income taxes to the utility customers. Accordingly, the impact of rate increases is substantially reduced at the customer level. Until recently, the process of rebating was lengthy and resulted in delays of approximately one year between the date of payment of the federal taxes by the utilities and the date of rebate to the customers. Provincial legislation has now been passed in Alberta whereby income tax rebates will be made on a current basis.

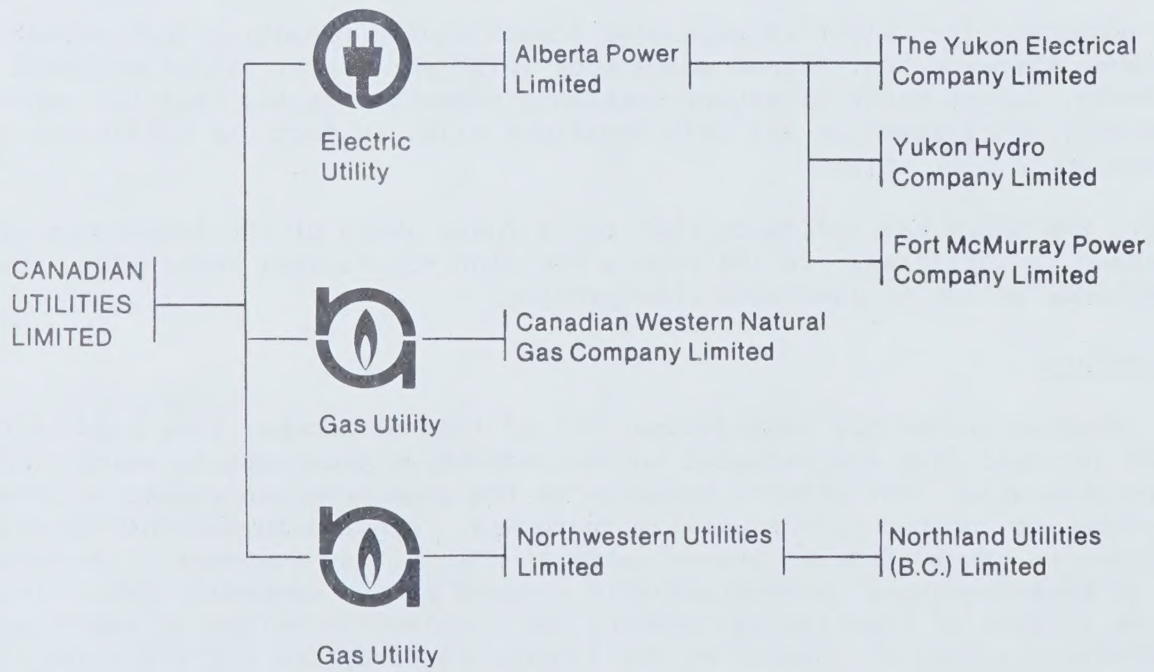
Natural Gas Rebates

Under Alberta's Natural Gas Rebates Act, gas consumers in the Province are sheltered from the full impact of the rapid increases in wellhead prices that occur as gas prices move towards their true commodity value in accordance with the Alberta government's policies. However, only customers using less than one billion cubic feet annually are completely sheltered. Under the Rebates Act, the provincial government pays the utilities, on a current basis, the difference between the price paid for natural gas by the utilities and the government support price. In order to recover the higher costs of natural gas sold to customers who use more than one billion cubic feet annually and are not fully sheltered, the Public Utilities Board allows higher rates on such sales.

THE COMPANY

Canadian Utilities Limited is the only investor-owned utility in Canada with major operations in both electric and gas service. Its electric operations do not supply major cities, but service over 600 communities, principally in east-central and northern Alberta and, to a lesser extent, in the Yukon and Northwest Territories. In June, 1974, the Company sold all the shares of Uranium City Power Co. Ltd. to the Saskatchewan Power Corporation, thereby eliminating the operations in Saskatchewan other than service to Lloydminster. Its major markets for the sale of natural gas are in Edmonton, Calgary, Lethbridge, Red Deer, and Grande Prairie. In total, 254 communities are supplied with gas by CU's subsidiaries.

Effective January 5, 1972, a corporate restructuring took place, making CU a holding company and the parent company of three major wholly-owned subsidiaries. Alberta Power Limited ("APL") was incorporated to assume the electric operations of the former Canadian Utilities Limited, while the two natural gas subsidiaries, Canadian Western Natural Gas Company Limited ("CWNG") and Northwestern Utilities Limited ("NUL"), continued their former operations. The restructuring was effected through share exchanges based on assessed values for each company. In the process, the natural gas operations of Northland Utilities Limited (except those in British Columbia) were transferred to NUL and its electric operations to APL.



From Canadian Utilities Limited, "Facts and Figures 1974".

Negotiations are under way concerning the sale of the electric operations in the Yukon and Northwest Territories to the Northern Canada Power Commission.

SUBSIDIARY COMPANY HIGHLIGHTS

ALBERTA POWER LIMITED

APL is CU's most important subsidiary, contributing approximately one-half of consolidated net income. It ranks with Calgary Power Ltd. as one of the fastest growing electric utilities in Canada.

Generating Capacity

With the completion and commissioning of the fourth generating unit at Battle River station in the latter part of 1975, total generating capacity will have almost doubled over a four-year period.

APL - GENERATING CAPACITY
(MW)

1971	367
1972	520
1973	522
1974	523
1975E	678
1976E	678

The 150 MW fourth unit at Battle River has been under development and construction since mid-1971, indicating a lead time of approximately 4 1/2 years for the additions of major new plants. The latest unit, however, should take care of production requirements for three to four years. The next major expansion is the planned construction of a fifth unit at Battle River with a generating capacity of 375 MW. This unit alone will add 55% to year-end 1975 capacity. The lead time for construction will likely exceed that of the fourth unit and commissioning of the fifth unit may not take place until after 1980.

Fuel Supply

Approximately 75% of APL's electrical energy generation was produced from coal in 1974, with the remainder provided by natural gas. The quantity of coal required by APL in 1975 is estimated at 1.2 million tons, which is being purchased from mines adjacent to the generating stations. Although the price of coal has been rising rapidly, the current price is still low relative to other fuels at an estimated 13 - 15 cents per million Btu. After the completion of the fifth unit at Battle River, coal requirements at this plant are estimated to average 2.8 - 2.9 million tons annually over the longer term.

Rate Base Expansion

In recent years, the largest portion of APL's capital expenditures has been incurred to increase generating capacity. The total cost of the fourth unit at Battle River is approximately $58.8 million, including environmental outlays of approximately $10.0 million. In addition, the Company has spent approximately $5.0 million on anti-pollution facilities at its H.R. Milner plant.

The impact of a heavy capital expansion program over several years is reflected in APL's rate base:

APL - RATE BASE GROWTH
(Millions of dollars)
(Approx.)

1971	100.0
1972	120.0
1973	140.0
1974	165.0
1975E	200.0
1976E	250.0

The average rate base growth is approximately 20% annually during the period shown. The 1976 increase in rate base will be almost 25% as the fourth unit at Battle River enters service.

Over the next few years, average annual electric capital expenditures are expected to stay around the 1975 level of approximately $40 million. One of the larger projects in the medium term is the construction of a new transmission line from a point near Slave Lake to the Syncrude development near Fort McMurray. This line is expected to be completed in 1977 at a cost of some $16.0 million. The level of annual expenditures is likely to rise well above $40 million when construction of the fifth unit at Battle River commences. Total cost of this facility, which may be shared with other Alberta utilities, will likely exceed $200 million.

Electric Sales

In 1974, APL's electric sales increased 11% in the residential and commercial sector. The strongest growth occurred at Fort McMurray, where energy sales increased 36%. APL has an isolated power plant in Fort McMurray which experienced a 60% increase in peak load last year. In order to supply the immediate load growth in this area, the Company plans to install four portable generating units. The construction of the new transmission line will result in a further substantial increase in power supply by 1977. The line will support the large electrical needs of the Syncrude Canada plant as well as tieing the town of Fort McMurray to the provincial electrical grid.

There was relatively little growth in APL's industrial sales in 1974 as the requirements of the petroleum industry levelled off. In that year, supply of electric service to oil and gas fields, primarily for oilfield pumping, accounted for 28% of total revenue. While the levelling of conventional crude oil production in Alberta affects the growth rate in sales to this category of industrial customer, it should be noted that higher energy per barrel of oil requirements should keep sales to this market at a high level.

Total electric sales will benefit from the various large scale industrial projects underway in the province and the accompanying growth in demand in the industrial and commercial categories. Oil sands development will create massive industrial growth, not only in the Athabasca area but also along the development corridor between Fort McMurray and Edmonton. Proposals have already been made to build a pipeline, two oil refineries, and several petrochemical plants along this corridor. About half the length of the corridor and a number of the industrial sites are within APL's service areas.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED AND NORTHWESTERN UTILITIES LIMITED

In terms of annual gas consumption, the Province of Alberta ranks second among Canadian provinces, after Ontario. In 1974, the total consumption in Alberta was almost 300 Bcf of which approximately 80% was supplied by CWNG and NUL. The combined service areas of these two companies cover most of the Province and include the cities of Edmonton, Calgary, and Lethbridge, as well as most other principal centres. Large industrial customers include fertilizer, chemical, cement, and lime plants as well as oil refineries, principally in the Edmonton area. Fort McMurray showed the fastest rate of growth in gas service in 1974.

Gas Supplies

In 1974, 48% of total gas supplies came from oilfields and gas plants, 27% from dry gas fields, and the balance from export and pipeline companies. NUL and CWNG obtained 34% and 3% of their respective requirements from principally company-owned reserves. At the end of 1974, CU controlled an estimated 3.0 Tcf of gas reserves of which over 800 Bcf are owned outright and 2,200 Bcf are under firm contract. An additional volume of almost 3.0 Tcf is estimated to be available for purchase in the future from fields where the expected gas producing life exceeds the terms of the existing gas purchase contracts and from other non-committed fields. These reserves, which are sufficient for approximately 25 years of supply at the 1974 rate of consumption, exclude any amounts that may be purchased under agreements with export companies. In 1974, 19% of the total gas supplies were obtained as a result of agreements with the four major export companies. These contracts enable CU to call on large quantities of both base-load and peak-load gas. The gas utilities also conduct a modest exploration program for development of gas reserves and additional deliverability of company-owned reserves.

Capital Expansion

The gas utilities, operating within areas considered to be relatively mature in terms of gas consumption, nevertheless are experiencing significant rate base expansion as shown in the following table:

APPROXIMATE COMBINED
RATE BASES OF GAS UTILITIES
(Millions of Dollars)

		% Increase Year-to-Year
1971	133	
1972	145	9%
1973	154	6
1974	171	11
1975E	189	10
1976E	208	10

The current growth rate is approximately 10% annually. While this is only about half the rate of growth being experienced by APL, it is well above the level expected some years ago.

Gas Sales

The gas utilities are expected to be major beneficiaries of the acceleration in the demand for gas from new industrial operations in Alberta. In 1976, CWNG's gas sales are expected to rise approximately 25%, mainly due to the commencement of deliveries to two new fertilizer plants. Deliveries to Cominco's new plant located at Carseland and to Canadian Fertilizers Ltd.'s plant at Medicine Hat are scheduled to begin in 1976. The combined maximum daily volumes under these contracts, without taking into account possible future expansion, are approximately 100,000 Mcf/d. The requirements of these two customers alone represent a 15% potential increase in total 1974 gas sales volumes of CWNG and NUL combined. The capital expenditures required to connect the two new plants contribute significantly to the rate base growth of the gas utilities.

Another example of the potential for new gas sales is the major petrochemical complex near Red Deer which is now moving into the development stage. The core of this complex is the world scale ethylene plant to be built under sponsorship of the Alberta Gas Trunk Line Company Limited. The ethylene output will be sold to chemical companies which plan to build large scale facilities for the conversion of ethylene into first-line derivatives such as low density polyethylene and vinyl chloride. The capital investments in the ethylene and derivative plants and supporting facilities are expected to be in the area of $1.5 billion. NUL has already offered to supply the gas fuel requirements of these plants, which will be located within its service area.

CONSOLIDATED FINANCIAL POSITION

The corporate restructuring that took place in 1972 has facilitated the financing of the group's external capital requirements. Since the reorganization took place, all permanent financing has been done through CU, which in turn finances the requirements of the subsidiaries. This method has made it possible to issue larger amounts at less frequent intervals. Prior to the restructuring, the typical average size of issues by the affiliated companies was $10 million. Under its new corporate organization, CU has publicly marketed a $30 million and a $17.5 million debenture issue, a $30 million preferred share issue, and privately placed two $15 million debenture issues. The following is the consolidated pro forma capitalization:

CONSOLIDATED PRO FORMA CAPITALIZATION (1)
DECEMBER 31, 1974

		($'000)	% of Total
Short-Term Notes Payable		19,105	4.8
Long-Term Debt		198,035	49.4
		217,140	54.2
Minority Interest (2)		20,008	5.0
Preferred Shares, Non-Convertible			
5% Series, $100 par value	4,000		
4 1/4% Series, $100 par value	1,500		
6% Series, $100 par value	5,000		
10 1/4% Series A, $25 par value	30,000	40,500	10.1
$1.25 Convertible Preferred Shares, $25 par value		35,453	8.8
Common Shareholders' Equity (10,075,466 shares)		87,871	21.9
		400,972	100.0

Notes:

(1) After giving effect to the issue of $30 million 10 1/4% preferred shares in January, 1975, and the application of the net proceeds, estimated at $29,020,000, to the reduction of short-term notes outstanding December 31, 1974.

(2) Minority interest represents subsidiary preferred shares not owned by CU.

The Company's financial position is expected to improve significantly as a result of the anticipated conversion of convertible preferred shares and a proposed new common equity issue, which will also lead to improved marketability, and a contemplated change in accounting methods, which will result in higher interest coverages.

As at December 31, 1974, there were 1,772,659, $1.25 preferred shares outstanding convertible into 2.0 common shares up to January 15, 1982 and 1.6 common shares up to January 15, 1992. At the current indicated dividend rate on the common shares of $0.74 per share, conversion of the preferred at the present conversion rate would increase dividend income from $1.25 per preferred share to the equivalent of $1.48 per share. As a result, it is reasonable to expect that all or most of the preferred shares will be exchanged for common shares. Full conversion of the $1.25 preferred shares would increase the common equity portion of the pro forma capitalization as of December 31, 1974 from 21.9% to 30.7%. The book value of the common equity would increase from $87,871,000 to $123,324,000 or from $8.72 per share to $9.05 per share.

IU International Corporation owned 8,720,084 common shares or 86.6% of the shares outstanding at the end of 1974. IU also owned 1,098,293 $1.25 convertible preferred shares, or 62.0%, at the same date. Assuming full conversion of the $1.25 preferred shares, the number of common shares outstanding will increase to 13,620,784 shares, of which IU will hold 10,916,670 shares or 80.1% and other shareholders will hold 2,704,114 common shares or 19.9%. It is anticipated that the common equity issue this fall will be offered to shareholders other than IU. Consequently, we estimate that the net float of CU common shares will approximate 3.9 million. Furthermore, at the end of 1974, there were warrants outstanding entitling holders to purchase 595,160 common shares at $9.00 per share up to May 15, 1978. Considering the current market price of the stock, it is reasonable to expect that these warrants will be exercised.

Due to the change in the provincial legislation whereby income tax rebates will be made on a current basis, CU's subsidiaries plan to change their depreciation rates claimed for income tax purposes commencing in 1976. In place of the accelerated depreciation allowed for income tax purposes, future depreciation for tax purposes will conform to actual book depreciation. The change in accounting methods will result in significantly higher federal income tax liabilities. The rationale for the change in depreciation policies is that this action will increase substantially CU's ability to issue long-term debt due to the fact that interest coverage calculations under terms of the trust indenture are based on earnings before income taxes. In time, the higher interest coverages should have a favourable effect on CU's cost of debt financing.

Summary of Earnings

The following table provides a summary of earnings in recent years, before and after the 1972 corporate restructuring, together with forecasts for 1975 and 1976:

SUMMARY OF EARNINGS

CU - Operating Earnings Contributions by Subsidiaries 1970-1976E

($'000)	1970	1971	1972	1973	1974	1975E	1976E
Subsidiary Companies (1)							
Alberta Power	4,618	6,039	7,504	7,467	7,623	13,102	15,127
Canadian Western	2,126	2,598	3,614	3,146	2,921	4,405	4,930
Northwestern	3,857	4,258	3,987	4,000	4,459	5,408	6,458
Parent Company	-	-	26	(238)	257	-	-
Consolidated Net Income	10,601	12,895	15,131	14,375	15,260	22,915	26,515
Less: Pfd. Dividends	2,514	2,514	2,766	2,787	2,781	5,856	5,856
Net Income Avail.Common	8,087	10,381	12,365	11,588	12,479	17,059	20,659
Earnings Per Share ($)							
Basic	0.90	1.03	1.23	1.15	1.24	1.66	1.83
Fully Diluted (2)	0.80	0.91	1.05	0.99	1.05	1.35	1.50
No.of Shares Used in E.P.S. Calculations							
Basic ('000)	8,949	10,056	10,063	10,065	10,075	10,275	11,275
Fully Diluted ('000)	12,669	13,766	14,216	14,216	14,216	14,415	15,415

Notes:

(1) Subsidiary earnings contributions are before intercompany preferred dividends payable to the parent company. Such dividends are deducted from consolidated net income.

(2) The calculations of fully-diluted earnings per share assume that (1) the outstanding $1.25 convertible preferred shares are fully converted at the beginning of each year, (2) the outstanding warrants are exercised at the beginning of each year and the proceeds are invested to yield 8% annually before applicable income taxes, and (3) the proposed new issue will increase the number of shares outstanding by 8% - 10%.

Growth Trends 1969 - 1976E

The following is a discussion of the Company's growth in capital expansion and operations and their impact on revenues, expenses, and net income. The accelerating trend in CU's capital expansion and the increasing relative importance of the electric operations are reflected in the statistics shown in the following table.

CU - CAPITAL EXPENDITURES AND GROSS PLANT IN SERVICE 1969-1974

	Capital Expenditures (Millions of Dollars)			Gross Plant in Service (Millions of Dollars)		
	Electric	Gas	Total	Electric	Gas	Total
1969	15.2	11.8	27.0	132.3	200.7	333.0
1970	16.3	12.3	28.6	147.5	211.9	359.4
1971	29.0	10.9	39.9	175.5	221.8	397.3
1972	24.7	16.9	41.6	198.2	237.7	435.9
1973	21.4	16.6	38.0	218.2	252.1	470.3
1974	45.0	27.0	72.0	260.7	277.9	538.6
1975E	45.0	23.0	68.0	303.0	299.0	602.0
1976E	40.0	30.0	70.0	340.0	328.0	668.0

During the period 1969 - 1974, approximately 60% of total capital additions were incurred in the electric operations and 40% in the gas operations. As a result, electric gross plant increased 97% during five years to the end of 1974 compared with a 38% increase in gross plant of the gas operation. The major reason for the heavy electric expenditures in 1974 and 1975 was the investment of approximately $58 million in the construction of a fourth generating unit at CU's Battle River plant. This unit will go into service in late 1975 and increase total generating capacity 30% from 523 MW to 678 MW. A continued high level of expenditures is expected to be maintained based on planned expansions of transmission and distribution facilities and the impact of inflation on construction costs. Similar type expenditures and the acquisition of major new industrial customers will increase the level of gas operation outlays.

The growth in sales closely matched the relative increases in gross plant investment during the 1969-1974 period.

CU - GROWTH IN CUSTOMERS AND SALES 1969-1971

	Customers at Year-End		Sales	
	Electric	Gas	Electric (Mil. kwhrs.)	Gas (Bcf)
1969	72,042	278,412	967	173
1970	74,193	289,457	1,118	187
1971	77,246	303,253	1,275	207
1972	80,492	317,766	1,520	232
1973	84,598	335,494	1,783	240
1974	88,822	353,331	1,920	240
1975E	93,200	373,000	2,060	260
1976E	96,300	393,000	2,230	300
Compound Annual Growth Rates				
1969-1974	4.3%	4.9%	14.7%	6.8%
1974-1976E	4.1%	5.5%	7.8%	11.8%
1969-1976E	4.3%	5.1%	12.7%	8.2%

Gas sales would have grown more rapidly during the 1969 - 1974 period had it not been for the impact on sales volume of warmer than normal weather in the last two years. During these two years, the average consumption per residential customer declined.

In 1975 and 1976, the trend in electric sales is expected to continue strong. Natural gas sales volumes are expected to rise at a well above average rate, reflecting colder average temperatures experienced in the first half of 1975 and large new industrial sales contracts in 1976.

While substantial growth took place in capital expansion and operations from 1969 to 1974, this was not reflected in corresponding improvements in earnings per share as shown in the table below.

CU - SELECTED INCOME STATEMENT STATISTICS 1969-1976

	Revenues			Gas Supply	Operating and	Interest	Net Income (1)	
	Electric	Gas	Total	Costs	Maintenance Costs	Expense	Total	Per Share (2)
	Thousands of Dollars							($)
1969	21,968	59,221	81,189	21,330	23,812	7,638	8,042	0.80
1970	27,666	62,972	90,638	22,695	26,365	9,108	8,087	0.80
1971	30,552	70,342	100,894	26,982	29,103	9,981	10,345	0.91
1972	33,849	78,875	112,724	32,357	33,389	12,159	12,365	1.05
1973	38,305	82,066	120,371	35,907	34,729	13,690	11,588	0.99
1974	46,295	91,486	137,781	40,179	43,572	17,127	12,479	1.05
1975E	58,500	125,000	183,500	77,000	55,000	19,900	17,059	1.35
1976E	78,000	180,000	258,000	155,000	65,000	21,400	20,659	1.50
Compound Annual Growth Rates								
1969-74	16.1%	9.1%	11.2%	13.5%	12.8%	17.5%	9.2%	5.6%
1974-76E	30.0%	40.0%	37.0%	96.0%	22.0%	11.8%	29.0%	19.5%
1969-76E	19.8%	17.2%	18.0%	33.0%	15.4%	15.9%	14.4%	9.4%

Notes:
(1) Net operating income after preferred dividends.
(2) Fully diluted.

Growth in net operating income available for the common shareholders lagged behind the growth in revenues although averaging a respectable 9.2% average annual increase. On a per share basis, this growth rate was reduced to approximately 5.6% annually due to an increase in the number of common shares outstanding following a 1-for-3 rights issue to shareholders in late 1970. In the period 1972-1974, gas supply expenses rose 24%, operating and maintenance costs increased 31%, and interest expenses climbed 41%. Revenues, on the other hand, were only 22% above the 1972 level. There were no rate increases in 1973 and the increases granted in 1974 were not sufficient to offset the effects of the large cost increases. The sharply rising expenses can be directly attributed to inflationary trends, trends in operating costs, higher interest rates, and, more importantly, the large capital expenditure program undertaken by the Company.

The large percentage increases in revenues projected from 1974 to 1976 reflect the extraordinary rate increases required to offset the near doubling in gas supply costs caused by sharply rising gas wellhead prices during this period. In addition, the forecast revenue gains reflect the recovery in the rate structures of other cost of service items including higher income tax provisions as well as higher levels of return on rate base for

each of the three subsidiaries. The following section includes our calculations of net income for 1975 and 1976 as set out in the table on page 16.

1975 and 1976 Earnings Forecasts

Earnings in 1975 and 1976 will reflect the higher returns on rate base granted in rate decisions this year as compared with those in effect in the previous five years. The need for more frequent rate increases became apparent last year as a result of strong inflationary trends in operating costs and rapidly rising interest expenses during the past two years.

RATE DECISIONS AND RATES OF RETURN ON RATE BASE 1959-1975

Alberta Power		Canadian Western		Northwestern	
Effective Date	Rate of Return	Effective Date	Rate of Return	Effective Date	Rate of Return
1969 (Dec.17)	8 1/2%	1971 (Feb.1)	8 5/8%	1959 (Sept.1-Nov.6)	7 1/2%
1974 (June 1)	9.3%	1974 (Aug. 1)	9 1/2%	1975 (Jan.1)*	8.9%
1975 (Aug.1)*	10 - 10.4%	1975 (Sept.1)*	10 1/4-10 3/4%	1975 (Oct. 1)*	10 - 10 1/2%

* Interim increases.

The rates in effect in 1974 produced the following return on average common equity of the subsidiaries and the parent company:

Alberta Power	-	12.4%
Canadian Western	-	11.7%
Northwestern	-	14.6%
CU-Consolidated	-	13.1%

The 1975 rate decisions are estimated to produce returns on average common equity of approximately 15% for 1975 and 1976. The following table details the average common equities of each of the subsidiaries and the parent company:

CU SUBSIDIARIES - AVERAGE COMMON EQUITIES

	1974	1975E	1976E
	(Thousands of Dollars)		
Alberta Power	56,675E	66,500	80,000
Canadian Western	24,908	28,000	31,500
Northwestern	30,534	34,000	41,000
CU-Consolidated	112,117	128,500	152,500

The 1974 figures for CWNG and NUL are derived from their annual reports. The figure for APL represents the residual of CU's consolidated common equity, which assumes full conversion of the $1.25 preferred shares. An adjustment was made to the book value of CWNG's common equity, which is also reflected in the consolidated figure, eliminating an amount of $8.0 million which is not recognized as part of the rate base for regulatory purposes. The amount represents "Undertakings, franchise and gas rights" included in CWNG's plant, property and equipment.

With respect to the growth in common equity projected for 1975 and 1976, the assumption was made that most of the common equity funds expected to be raised this fall will be channelled to Alberta Power due to this company's large capital requirements. A smaller portion has been allocated to Northwestern as CWNG does not appear to be in need of additional common equity at this time. It is expected that CWNG will generate a relatively significant amount of equity funds in the near future in the form of gains on sale of certain properties.

The following table shows net income by subsidiary and on a consolidated basis for 1974 together with estimates for 1975 and 1976. The table also shows a reconciliation of these figures with those included in the table "Summary of Earnings" on page 14.

NET INCOME BY SUBSIDIARIES AND CONSOLIDATED NET INCOME 1974-1976

	1974	1975E	1976E
	(Thousands of Dollars)		
Alberta Power	7,059E	9,975	12,000
Canadian Western	2,921	4,200	4,725
Northwestern	4,459	5,100	6,150
	14,439	19,275	22,875
Add: Preferred dividends paid to parent company (1)	564	3,640	3,640
	15,003	22,915	26,515
Add: Parent company income	257	-	-
Consolidated net income	15,260	22,915	26,515

(1) The amounts of preferred dividends paid by the subsidiaries to the parent company reflect the allocation of the $30 million 10 1/4% preferred shares issued by CU in January, 1975, in amounts of $25 million to Alberta Power; $2 million to Canadian Western; and $3 million to Northwestern.

Longer-Term Outlook

With rate regulation in effect linking earnings to allowable levels of return on common equity, the growth in CU's utility income over the longer term will tend to parallel the growth in its common equity. The growth in common equity arises basically from retained earnings and from other sources such as conversions of senior securities, sales of additional shares, and exercise of warrants. The amounts of retained earnings depend primarily on the Company's dividend payout policy. The increase in CU's common equity arising from conversion of the $1.25 preferred shares and the proposed sale of common shares this fall already is included in the amount of common equity to which the allowable return is related. The potential increase in equity from the exercise of the outstanding warrants which expire May 15, 1978 is minimal, since exercise of all warrants would only increase the total number of shares outstanding by approximately 4%.

Assuming that CU's rate structure will continue to provide a return of approximately 15% on common equity and further assuming that the Company will continue its policy of paying out 50% - 55% of its common share earnings in dividends, the longer-term growth rate in common equity and earnings per share, after 1976, should average approximately 7% annually.

CARL BREIDA, CFA
(514) 844-0131

SEPTEMBER 26, 1975
MONTREAL, QUEBEC

* * *

PLEASE BE ADVISED THAT NESBITT THOMSON AND COMPANY LIMITED HAS ACTED AS FISCAL AGENT AND UNDERWRITER TO CANADIAN UTILITIES LIMITED. IN THE EVENT THAT NEW SECURITIES ARE OFFERED TO THE PUBLIC, NESBITT THOMSON AND COMPANY LIMITED MAY PARTICIPATE IN SUCH AN OFFERING AND RECEIVE A FEE FOR ITS SERVICES.

ADDITIONAL SUPPORTING INFORMATION IS AVAILABLE ON THE SECURITIES MENTIONED HEREIN.

THE FOLLOWING INCLUDES THE NAME OF EVERY PERSON HAVING AN INTEREST EITHER DIRECTLY OR INDIRECTLY TO THE EXTENT OF NOT LESS THAN 5% IN THE CAPITAL OF NESBITT THOMSON AND COMPANY LIMITED: A.D. NESBITT, J.I. CROOKSTON, J.R. OBORNE, J.R. LEARN, D.E.M. SCHAEFER, D.N. STOKER, R.W. CROSBIE, J.B. AUNE, AND P.G. VIEN.

APPENDIX A

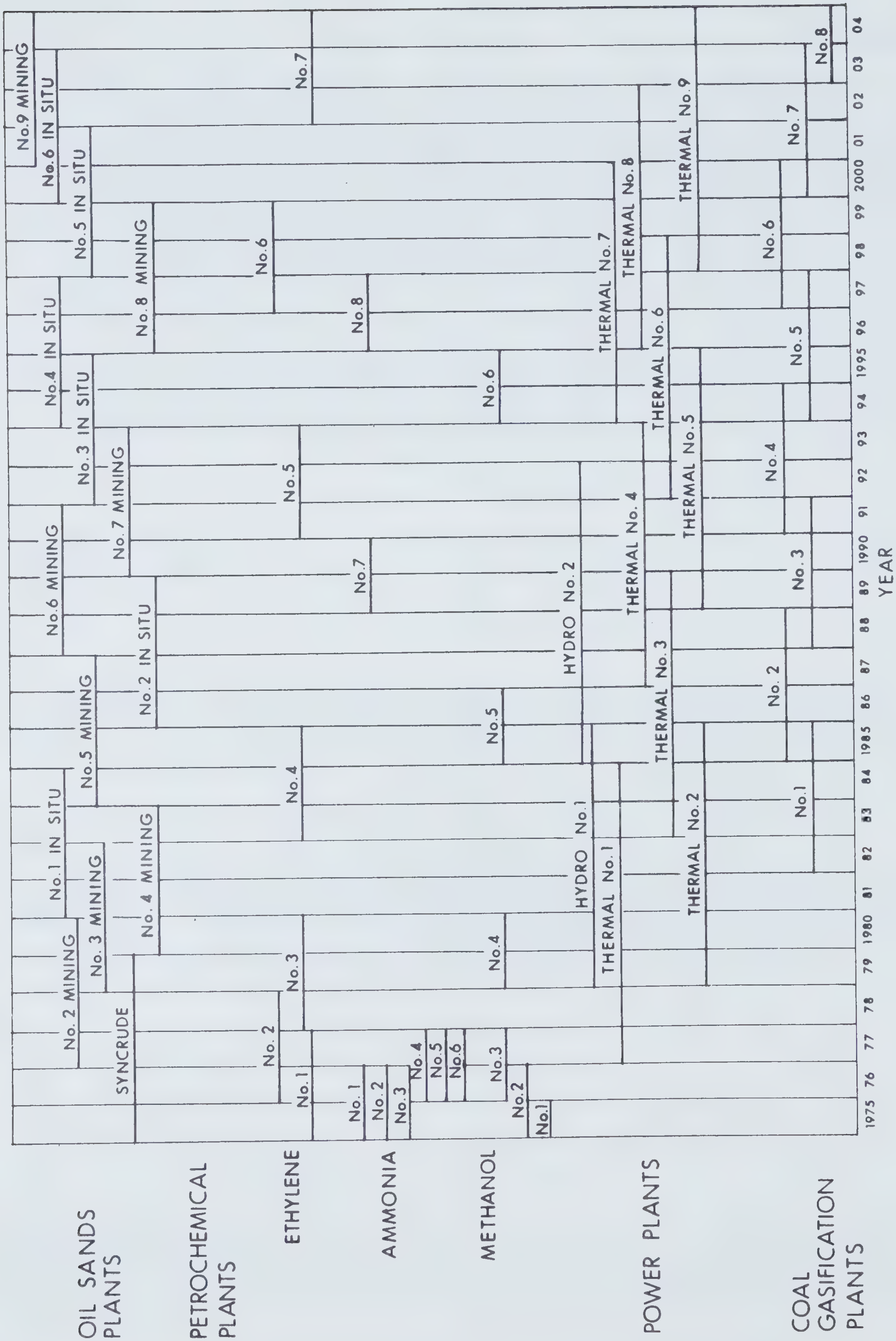


FIGURE A-1 ILLUSTRATIVE FORECAST OF CONSTRUCTION PERIOD FOR MAJOR INDUSTRIAL PROJECTS IN ALBERTA

OCTOBER 9, 1975

nesbitts latest

J E M

RECEIVED BY

OCT 14 1975

J. E. M. OFFICE

CANADIAN UTILITIES LIMITED
PRICE 9 1/8

P/E E 6.7

YIELD 8.1 PCT

SUBSEQUENT TO THE PUBLICATION OF OUR REPORT ON CU, DATED SEPTEMBER 26,1975, IT HAS BEEN ANNOUNCED THAT THE COMPANY PLANS TO PARTICIPATE IN THE PROPOSED PETROCHEMICAL COMPLEX IN ALBERTA, SPONSORED BY ALBERTA GAS TRUNK LINE, DOW CHEMICAL, AND DOME PETROLEUM.

CU'S PARTICIPATION WILL TAKE THE FORM OF A 50 PCT INTEREST, JOINTLY WITH DOME, IN A GAS PROCESSING PLANT WHICH WILL EXTRACT ETHANE, PROPANE, AND BUTANE FROM THE COMPANY'S NATURAL GAS STREAM. THE PLANT WILL PRODUCE APPROXIMATELY 20,000 B/D OF ETHANE AND APPROXIMATELY 5,000 B/D OF PROPANE AND BUTANE. A PORTION OF THE ETHANE WILL BE DELIVERED TO A CHEMICAL PLANT TO BE BUILT BY ALBERTA GAS TRUNK LINE TO CONVERT THE ETHANE INTO ETHYLENE. THE VOLUMES OF ETHANE, WHICH ARE SURPLUS TO TRUNK LINES REQUIREMENTS, WILL BE EXPORTED FROM ALBERTA VIA THE PROPOSED COCHIN PIPELINE TO BE BUILT BY DOW AND DOME. THE PIPELINE WILL BE DESIGNED TO CARRY BOTH ETHANE AND ETHYLENE FROM ALBERTA TO MARKETS IN EASTERN CANADA AND THE U.S. THE PROPANE AND BUTANE PRODUCTS WILL BE MARKETED BY DOME.

THE CAPITAL COST OF THE CU-DOME EXTRACTION PLANT IS ESTIMATED AT DLRS 40 MILLION, WHICH IS EXPECTED TO BE FINANCEED ON THE BASIS OF 75 DLRS DEBT AND 25 PCT COMMON EQUITY. THE PLANT WILL BE OPERATED ON A COST OF SERVICE BASIS WITH LONG TERM TAKE OR PAY CONTRACTS FOR THE ETHANE PRODUCTION. THE COST OF SERVICE WILL INCLUDE A RETURN ON COMMON EQUITY, WHICH IS EXPECTED TO EXCEED THE RETURN OF APPROXIMATELY" 15 PCT BEING EARNED BY CU ON EQUITY INVESTED IN ITS UTILITY OPERATIONS. ADDITIONAL EARNINGS WILL BE GENERATED FROM THE MARKETING OF PROPANE AND BUTANE.

ITS EXPECTED THAT CU ALSO WILL BE OFFERED AN EQUITY INTEREST IN THE PROPOSED DLRS 260 MILLION COCHINE PIPELINE. WHETHER CU WILL EXERCISE THIS OPTION DEPENDS ON THE LEVEL OF RETURN OBTAINABLE FROM SUCH AN INVESTMENT.

THE ABOVE MENTIONED DEVELOPMENTS REPRESENT CU'S FIRST SIGNIFICANT DIVERSIFICATION MOVE FITING IN NATURALLY WITH ITS PRESENT OPERATIONS. THE EXTRACTION PLANT SHOULD BEGIN TO CONTRIBUTE EARNINGS BY MID-1978, WHEN THE WHOLE PETROCHEMICAL COMPLEX IS SCHEDULED TO BEGIN OPERATIONS. THE PROJECTS STILL REQUIRES VARIOUS GOVERNMENTAL APPROVALS IN ALBERTA AND OTTAWA. THESE ARE EXPECTED TO BE GRANTED IN THE NEAR FUTURE. WE CONTINUE TO RECOMMEND CU COMMON AS BEING UNDERVALUED RELATIVE TO MOST OTHER UTILITY STOCKS. CONSIDERING THE COMPANY'S FAVOURABLE OPERATING ENVIRONMENT IN ALBERTA.

FULLY DILUTED OPERATING E.P.S. ARE EXPECTED TO ~~RESI~~ Rise 26 PCT FROM DLRS 1.05 IN 1974 TO 1.35DLRS IN 1975 AND TO INCREASE BY A FURTHER 11 PCT TO DLRS 1.50 IN 1976.

WE REPEAT OUR RECOMMENDATION TO HOLDERS OF CU DLRS 1.25 CONVERTIBLE PREFERRED SHARES TO EXCHANGE THIS STOCK FOR COMMON SHARES TO ACHIEVE AN EFFECTIVE INCREASE OF 18.4 PCT IN ANNUAL DIVIDEND INCOME.

CARL BREIDA

CANADIAN UTILITIES LIMITED

1975

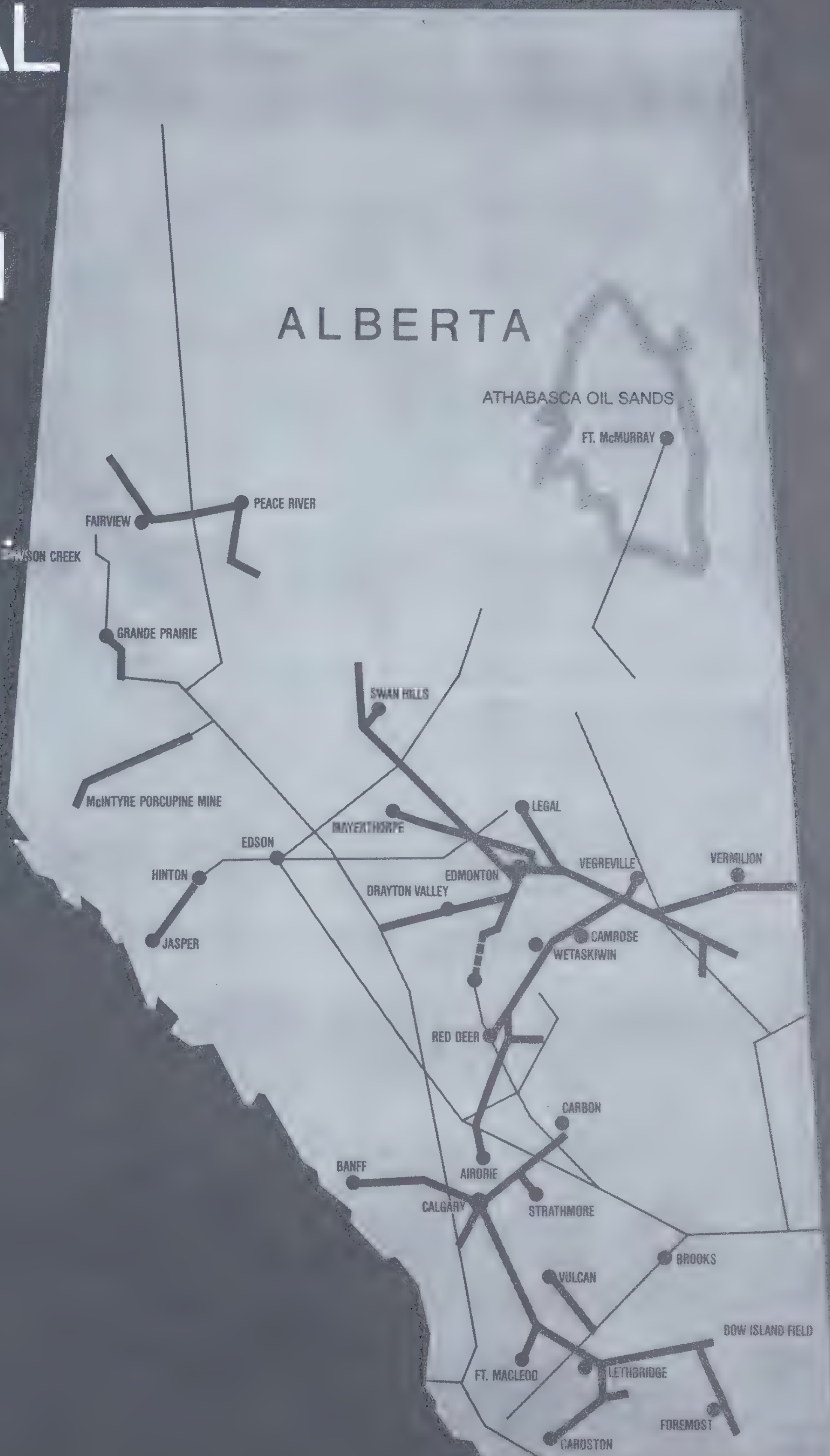
AN ALBERTA GROWTH COMPANY

CANADIAN UTILITIES LIMITED

ELECTRIC SYSTEM

CANADIAN UTILITIES LIMITED

NATURAL GAS SYSTEM

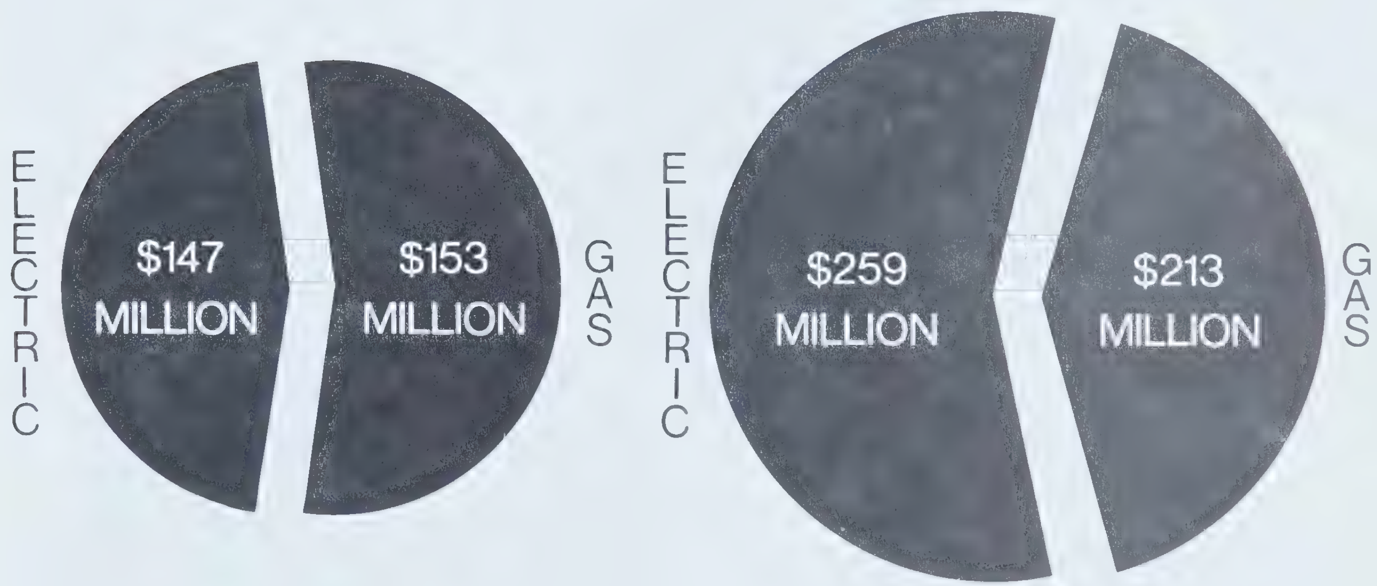


CANADIAN UTILITIES LIMITED

DISTRIBUTION OF

NET FIXED ASSETS

DEC.-71 | DEC.-75 (E)



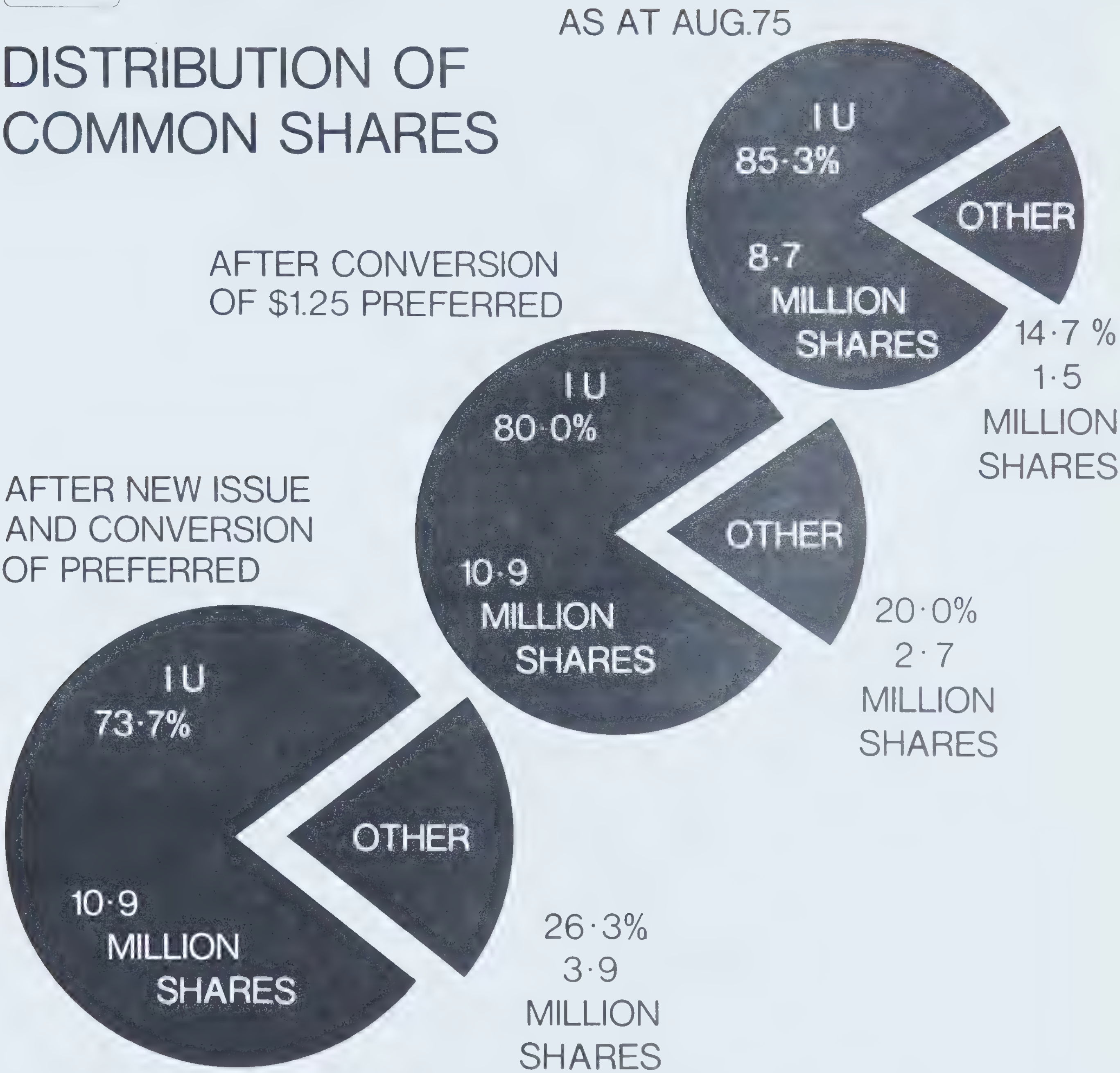
$300 MILLION | $ 472 MILLION

COMPOUND RATE
OF GROWTH

GAS	8·6%
ELECTRIC	15·2%
CUL TOTAL	12·0

CANADIAN UTILITIES LIMITED

DISTRIBUTION OF COMMON SHARES



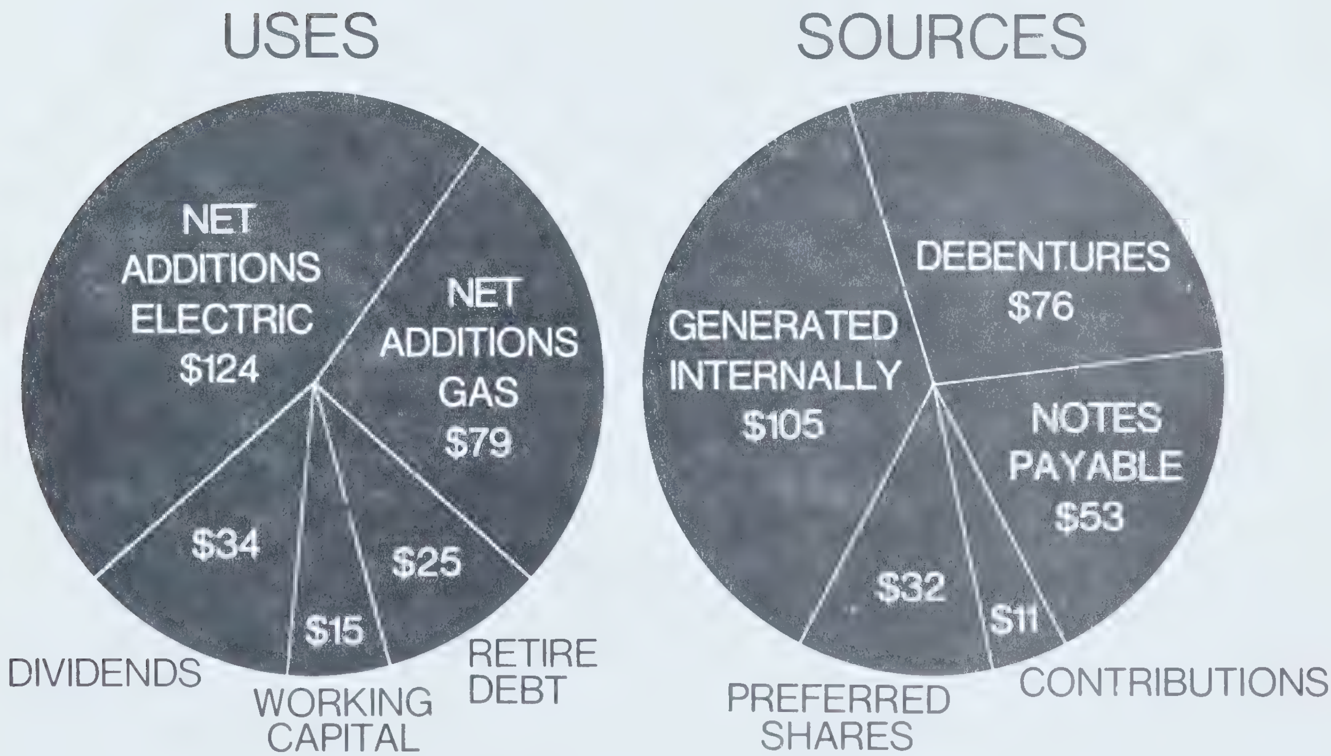
CANADIAN UTILITIES LIMITED

ANALYSIS OF

FUNDS FLOW

44 MONTHS - JAN 72 TO AUG 75

(IN MILLIONS)



$ 277 MILLION TOTAL

THE REGULATORY PROCESS - ALBERTA

FEATURES

- INTERIM RATES
- FUTURE TEST YEARS
  - PROJECTED COSTS AND REVENUES
  - PROJECTED RATE BASE AND CONTENT
  - PROJECTED COST OF CAPITAL
- TIMELY DECISIONS AND CONDUCT OF CASE

DEBT EQUITY RATIO AND RETURN ON EQUITY

CANADIAN UTILITIES LIMITED

1975 RATE APPLICATIONS CURRENT STATUS

	N.U.L.	C.W.N.G.	A.P.L.
APPLICATION FILED	AUG 25	JULY 25	JULY 2
% RATE INCREASE			
-'75	3.3 %	8.2 %	21.3 %
-'76	5.9 %	7.0 %	TO BE DETERMINED
INTERIM RATES FOR FULL INCREASE AS REQUESTED EFFECTIVE	OCT. 1	SEPT. 1	AUG. 1
HEARING STARTS	DECEMBER	NOVEMBER	DECEMBER
R.O.E. FOR EQUITY -FINANCED COMPONENT OF RATE BASE....	14.8 %	15.0 %	14.3 %

CANADIAN UTILITIES LIMITED

RECENT DECISIONS ON 1974 APPLICATIONS

	N.U.L.	C.W.N.G.	A.P.L.
1975 UTILITY INCOME- REQUESTED($MILLION)	10.2	7.7	17.9
GRANTED....	10.2	7.7	17.9
% INCREASE IN REVENUES....	43.3 %	38.4 %	19.3 %
DATE DECISION RECEIVED....	SEPT. 1975	APR.1975	AUG.1975
– INTERIMS GRANTED.....	JAN. 1975	AUG. 1974	JUNE 1974

CANADIAN UTILITIES LIMITED

COMPARISON OF AVERAGE RESIDENTIAL UTILITY BILL... NOV. 1975

	GAS (6700 CU.FT/MONTH)	ELECTRIC (600 KWH/MONTH)
* EDMONTON	$ 8.18	
* LLOYDMINSTER		$ 18.30
DAWSON CREEK		25.39
VANCOUVER	10.00	
TORONTO	16.80	

* NET OF PROVINCIAL GAS REBATE BUT BEFORE TAX REBATE.

CANADIAN UTILITIES LIMITED

A COMPARISON OF INVESTMENT OPPORTUNITIES IN ALBERTA BASED COMPANIES

		CANADIAN UTILITIES	ALBERTA GAS TRUNK LINE	CALGARY POWER
NET FIXED ASSETS (MILLIONS)	-DEC. 1974	413.5	477.5	578.1
	-AUG. 1975	454.2		
COMMON EQUITY MID-YEAR (MILLIONS)	-1974	117.4	124.8	124.0
RETURN ON EQUITY	-1974	13.1%	11.7%	10.9%
	-1975 E	15.3% +	?	15.0%
ESTIMATED 1975 EARNINGS		1.35 to 1.53	1.07 to 1.10	3.30
RECENT MARKET PRICE		$9 1/4	$11 1/2	$25 1/4
PRICE EARNING RATIO (1975 EARNINGS)		6.85 to 6.05	10.75 to 10.45	7.65

CANADIAN UTILITIES LIMITED
DIVIDEND PAYOUT

	E.P.S. FULLY DILUTED (EXCLUDING EXTRA) $	COMMON DIVIDEND $/SHARE	DIVIDEND PAYOUT PERCENTAGE ACTUAL 4 QTRS.	DIVIDEND PAYOUT PERCENTAGE EFFECTIVE (LAST QTR.X4)
1972- 1Q		12.5		
2Q		12.5		
3Q		13.5		
4Q		13.5		
YEAR	1.05	52.0	50%	51%
1973- 1Q	0.55	13.5		
2Q	0.20	13.5		
3Q	0.02	13.5		
4Q	0.22	14.5		
YEAR	0.99	55.0	56%	57%
1974- 1Q	0.51	14.5		
2Q	0.26	14.5		
3Q	0.02	14.5		
4Q	0.26	15.5		
YEAR	1.05	59.0	56%	59%
1975- 1Q	0.50	15.5		
2Q	0.27	15.5		
3Q	0.16	15.5		
4Q	0.42	18.5		
YEAR	1.35 (E)	65.0	48%	55%

GROWTH IN QUARTERLY DIVIDEND RATE $\frac{18.5-12.5}{12.5} \times 100 = 48\%$

CANADIAN UTILITIES LIMITED

CALGARY POWER LIMITED
DIVIDEND PAYOUT

	E.P.S.	COMMON DIVIDEND	DIVIDEND PAYOUT ACTUAL 4 QTR.	DIVIDEND PAYOUT EFFECTIVE (LAST QTR X 4)
1972- 1Q		0.25		
2Q		0.25		
3Q		0.25		
4Q		0.25		
YEAR	2.36	1.00	42%	42%
1973- 1Q		0.25		
2Q		0.25		
3Q		0.25		
4Q		0.30		
YEAR	2.59	1.05	40%	46%
1974- 1Q		0.30		
2Q		0.30		
3Q		0.30		
4Q		0.30		
YEAR	2.65	1.20	45%	45%
1975- 1Q		0.35		
2Q		0.35		
3Q		0.45		
4Q		0.45		
YEAR	3.40 E	1.60	47%	53%

CU CANADIAN UTILITIES LIMITED

CONSUMERS GAS COMPANY
DIVIDEND PAYOUT

	E.P.S. $	COMMON DIVIDEND $/SHARE	DIVIDEND PAYOUT ACTUAL 4 QTRS.	DIVIDEND PAYOUT EFFECTIVE (LAST QTR. X4)
1972- 1Q		0.22		
2Q		0.22		
3Q		0.22		
4Q		0.22		
YEAR	1.20	0.88	73%	73%
1973- 1Q		0.22		
2Q		0.22		
3Q		0.22		
4Q		0.22		
YEAR	1.29	0.88	68%	68%
1974- 1Q		0.22		
2Q		0.22		
3Q		0.22		
4Q		0.25		
YEAR	1.39	0.91	65%	72%
1975- 1Q		0.25		
2Q		0.25		
3Q		0.25		
4Q		0.25		
YEAR	?	1.00		

CANADIAN UTILITIES LIMITED

ALBERTA'S ECONOMIC PERFORMANCE

COMPARISON OF GROSS DOMESTIC PRODUCT. ALBERTA AND CANADA

	G.D.P. ($MM)		% CHANGE IN G.D.P.		ALBERTA G.D.P. AS A % OF CANADA
	ALBERTA	CANADA	ALBERTA	CANADA	
1970	6,782	87,071	7.9	7.4	7.8
1971	7,349	94,883	8.4	9.0	7.7
1972	8,105	105,073	11.5	10.7	7.8
1973	10,175	120,736	24.2	14.9	8.4
1974(P)	12,046	141,726	18.4	17.4	8.5

PRIVATE & PUBLIC INVESTMENT IN ALBERTA

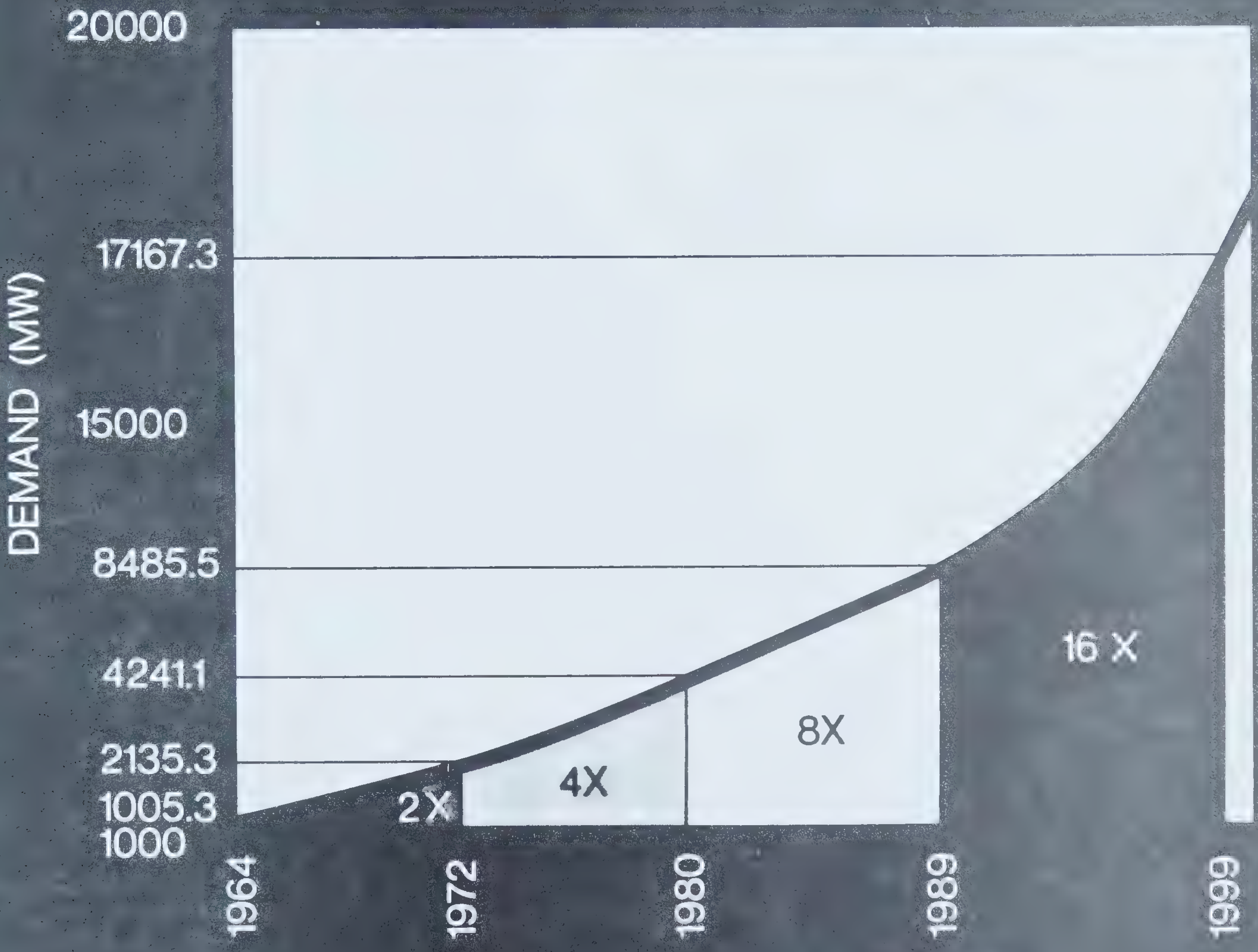
($ MILLION)

	1970	1971	1972	1973	1974	EST. 1975	5 YEAR % C.G.R.
PRIMARY INDUSTRIES AND CONSTRUCTION	878	946	1007	1253	1633	2038	18.3%
MANUFACTURING	184	187	246	394	409	414	17.7%
UTILITIES	496	472	501	557	763	1016	15.4%
TRADE, FINANCE & COMMERCIAL SERVICES	187	180	280	404	432	425	17.9%
HOUSING	350	492	538	588	701	680	14.2%
INSTITUTIONAL SERVICES & GOVERNMENT DEPARTMENTS	392	442	426	472	566	672	11.3%
TOTAL	2487	2719	2998	3668	4504	5245	16.1%


CANADIAN UTILITIES LIMITED
PLANNED PETROCHEMICAL DEVELOPMENTS IN ALBERTA 1975-1982
DOW CHEMICAL
Vinyl chloride monomer plant
-chloralkali plant
-styrene plant
-ethylene oxide plant
costs $350 MM
COCHIN PIPELINE
1900 miles-Edmonton-Green Springs, Ohio
Cost $240 MM
ALBERTA GAS ETHYLENE
PLANT NO. 1 (1978 start-up)
-ethane requirement 37,000 B/D
-output 1.2 billion lb. ethylene/yr
-cost $290 MM
PLANT NO. 2 (1981 start-up)
-ethane requirement 37,000 B/D
-output 1.2 billion lbs ethylene/yr
-cost $380 MM
FORT SASKATCHEWAN
EDMONTON
RED DEER
CALGARY
EDMONTON ETHANE EXTRACTION PLANT
-capacity 20,900 B/D C2
-cost $40 MM
COCHRANE ETHANE EXTRACTION PLANT
-capacity 27,300 B/D
-cost $50 MM
EMPRESS ETHANE EXTRACTION PLANTS (2)
Capacity: 63,000 B/D -cost $115 MM
PIPELINE LEGEND
estimated cost
Ethane gathering pipeline $28 MM
Ethylene pipeline 10 MM
Ethylene storage 10 MM
Cochine pipeline
$48 MM

CANADIAN UTILITIES LIMITED

ALBERTA INTERCONNECTED SYSTEM LOAD GROWTH



CANADIAN UTILITIES LIMITED

POTENTIAL COAL SOURCES FOR ELECTRIC POWER GENERATION

LEGEND

Coal Sources

CANADIAN UTILITIES LIMITED

ELECTRIC POWER GENERATION PLANNING

	COAL RESERVES TO SUPPORT	ADDITIONS SIZE	PLANNED TIMING
BATTLE RIVER	750 MW	375 MW	1981 (E)
SHEERNESS	750MW	375 MW	1987(E)

E - ESTIMATED COMMISSIONING DATE

CANADIAN UTILITIES LIMITED

ELECTRIC OPERATIONS - CAPITAL EXPENDITURES
($MILLION)

'73	'74	'75(E)		'76	'77	'78	'79	'80	'81
				FORECAST					
12	29	31	GENERATION	10	9	9	27	69	96
3	8	9	TRANSMISSION	16	23	14	11	22	25
5	6	7	DISTRIBUTION	6	6	7	8	8	9
1	2		OTHER	2	3	3	1	4	3
21	45	48	TOTAL	34	41	33	47	103	133

CANADIAN UTILITIES LIMITED

COAL SUPPLY AND COST

	MILNER	BATTLE RIVER
THOUSAND SHORT TONS CONSUMED IN 1975....	317	1151
COST IN - $ / TON (APPROX)	$ 1·3/4	$ 2·3/4
¢ / MMBTU	12¢	17¢
SUPPLY	ADJACENT TO Mc.INTYRE EXPORT COAL OPERATIONS.	OWNED BY LUSCAR: MANALTA AND C. U. L.

CANADIAN UTILITIES LIMITED

GAS OPERATIONS - CAPITAL EXPENDITURES

($MILLION)

'73	'74	'75 (E)		'76	'77	'78	'79	'80	'81
				Forecast					
9	16	16	N. U. L.	20	29	27	30	37	41
8	12	14	C. W. N. G.	18	18	19	20	21	23
17	28	30	TOTAL	38	47	46	50	58	64

NATURAL GAS SALES B.C.F. & M.B.T.U.

1970	1975E	5 YEAR COMPOUND GROWTH RATE		FORECAST 1975	FORECAST 1980	5 YEAR COMPOUND GROWTH RATE
		%				%
55	69	4.6	RESIDENTIAL	69	85	4.3
53	68	5.1	COMMERCIAL	68	85	4.6
79	125	9.6	INDUSTRIAL AND OTHER	125	202	10.1
187	262	7.0	TOTAL	262	372	7.3

CANADIAN UTILITIES LIMITED

NATURAL GAS SUPPLY

			NUMBER OF TIMES 1975 REQUIREMENT
• OWN	806	B.C.F.	
CONTRACT	2485	B.C.F.	
AVAILABLE	2638	B.C.F.	
	5929	B.C.F.	23

- CONTRACTUAL RIGHTS WITH GAS EXPORT COMPANIES

- GOVERNMENT POLICY

Canadian Utilities Limited / 1975 Annual Report

Contents

Cover: Seen through the steel maze of Alberta Power Limited's Battle River plant substation is one of the transmission towers which carry high voltage power lines from the coal-fired generating station.

Terminus of several major gas transmission lines serving the greater Edmonton area is Northwestern's No. 1 Gate Station. At this point, natural gas pressures are controlled, and volumes measured.

Highlights

	1975	1974	Increase (Decrease)
Revenues (thousands)			
Natural Gas	**$142,436**	$ 91,486	$ 50,950
Electric	**57,945**	46,295	11,650
Total	**$200,381**	$137,781	$ 62,600
Net earnings (thousands)	**$ 26,194**	$ 15,704	$ 10,490
Fully diluted earnings per common share*	**$ 1.61**	$ 1.08	$ .53
Dividends paid			
on common shares (thousands)	**$ 7,142**	$ 5,943	$ 1,199
per share	**.65**	.59	.06
Capital expenditures (thousands)	**$ 81,181**	$ 71,984	$ 9,197
Customers at year-end			
Natural Gas	**373,254**	353,331	19,923
Electric	**94,040**	88,822	5,218
Average annual use per residential customer			
Natural Gas (cubic feet)	**212,358**	208,376	3,982
Electric (kilowatt hours)	**6,774**	6,369	405

**Includes non-recurring gains of $2,329,000 or $.16 per share in 1975 and $444,000 or $.03 per share in 1974 as a result of the sale of property and certain utility distribution facilities in the respective years.*

To the Shareholders:

With the good fortune in 1975 to be operating in a provincial economy which proved strong enough to show real progress, despite a much less buoyant year in other parts of the nation, sales for our company increased in all segments of its business.

In contrast to the general trend elsewhere, there was relatively little relaxation in demand for continued expansion of our gas and electric services or in the corresponding necessity for new capital. The need to demonstrate sufficient earnings to attract new capital as well as to contend with large increases in operating costs, including major cost-pass-through elements such as upward adjustments of the government support price for natural gas, left the utility operations no choice but to apply for rate increases.

A combination of greater sales volumes and several rate increases resulted in consolidated revenues of $200,381,000. This exceeded the 1974 total by 45 per cent. Net earnings from operations were $23,865,000, up $8,605,000 from the previous year. Fully diluted earnings per common share rose to $1.45 compared to $1.05 in 1974. An additional 16 cents in non-recurring capital gains were recorded in 1975 bringing total earnings per common share fully diluted to $1.61. In 1974, an extraordinary gain of three cents raised total per share earnings to $1.08 fully diluted.

Rate matters are featured in other sections of this year's annual report, but it is important to observe here that our concerns regarding regulatory lag, to which attention was drawn in the 1974 annual report, have diminished with the past year's record of prompt action by the Alberta Public Utilities Board in granting interim rates.

The company's utility rates constitutionally have been subject to provincial regulation and under the terms of the recently signed federal/provincial agreement covering the application of the federal government's anti-inflation program in Alberta, it is provided that the national administrator shall not become involved in the regulatory rate-making process except on the request of the provincial cabinet. Nevertheless, it is difficult to view with equanimity the prospect of additional federal interventions in wage and price decisions that now appear on the horizon, possibly for all the private sector, and with some degree of permanence.

The company's capital requirements were met in part during the year by the issue of 1.1 million new common shares, which went on the market at $9.25. Earlier in the year there was a $30 million issue of 10¼ per cent preferred shares. As one further step to strengthen the equity portion of its capital structure, the company took advantage of an opportunity to sell a real estate property at a profit and reinvested the proceeds in utility plant under construction at the time. Just after the close of the year, the company proceeded with a $50 million debenture issue — the largest in its history.

An increase in the fourth quarter common share dividend from 15½ cents to 18½ cents resulted in conversion of a major portion of the 1.8 million $1.25 convertible preferred shares, originally issued in 1972. They are convertible on the basis of two common shares for each preferred share. The annual dividend that would result from the 18½ cent quarterly rate on the common shares would be in complete compliance with the current anti-inflation guidelines on dividends.

The utility companies distribute natural gas and electricity under authority granted by franchises, many of which are renewable at specified dates. During the past year, the very major natural gas franchise with the City of Edmonton was renewed for a further period of ten years to 1985.

One of the most notable events in Alberta in the past year was confirmation by the provincial government that it wishes to see a world-scale petrochemical industry established in the province. Petrochemicals promise to add yet another dimension through which the company might participate in Alberta's development. In this connection Canadian Utilities and Dome Petroleum have announced a joint venture to build and operate a 20,000 barrel-a-day ethane extraction plant located at Edmonton. This $40 million project is an integral part of the ethane-ethylene-based chemical complex which is visualized for the province, and for which the necessary construction approvals are currently being sought.

D. K. Yorath will not be standing for re-election as a director at this year's annual meeting. Dr. Yorath's appointment as Honorary Director will be proposed to the incoming Board of Directors as a sincere expression of respect and regard for a most distinguished record of service to Canadian Utilities and its subsidiary companies. His career with the companies has encompassed a wide range of responsibilities and spans a total of 52 years.

The company was saddened by the death on May 24, 1975 at age 86 of its warmly regarded Honorary Chairman, H. R. Milner, C.C., Q.C., a leading member of the Canadian business community for many years and an important figure in the formation and early growth of the companies in the Canadian Utilities group.

The past year has been an especially eventful and challenging one for all the CU companies. Maintaining vital gas and electric utility services in areas exposed to sudden climatic changes is never an easy task, but with the additional complexities imposed lately by rapid growth, inflation and rate case preparation, it becomes increasingly demanding. The record performances reported here are a tribute to the diligence and skill of the men and women who constitute CU and its operating companies.

On behalf of the Board of Directors

E. W. King

E. W. King, President

J. E. Maybin

J. E. Maybin, Chairman

March 12, 1976

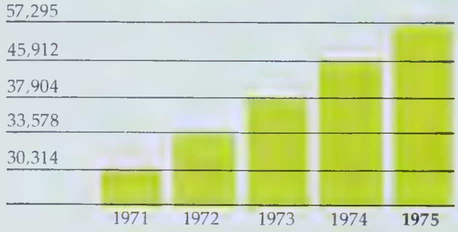
Electric Operations

Alberta Power Limited (APL) serves 347 communities in east-central and northern Alberta and parts of the Northwest Territories including Hay River and, through its subsidiary, The Yukon Electrical Company Limited, 18 communities in the Yukon. At year-end the company had 94,040 customers, up 5,218 from the previous year. Included were 20,415 farm customers, of whom 19,457 were members of 169 Rural Electrification Associations. During the year energy sales increased 5.4 per cent to 2,025 million kilowatt hours, while peak load grew 15 per cent to 445 megawatts.

Electric revenues in 1975 were $57,945,000, compared to $46,295,000 in 1974. The growth in revenues is attributable largely to increased rates permitted by the regulatory boards in Alberta, the Yukon and Northwest Territories to compensate for higher costs resulting from inflation. A 21.3 per cent interim rate increase went into effect in Alberta on August 1, and interim approval was received for a further increase of 8.0 per cent which took effect on January 1, 1976. Also during 1975, the Alberta Public Utilities Board approved a 19.3 per cent increase in revenue in connection with Alberta Power's 1974 rate submission. An interim rate increase to recover these additional revenues had been granted in June, 1974.

In July it was announced that the company had entered into negotiations with the federal government's electric utility, the Northern Canada Power Commission (NCPC), for the sale of The Yukon Electrical and other properties north of the 60th parallel. Although the Yukon company has been in operation since 1902, and brought good service to many northern settlements, the federal government has stated it wants further power generation and transmission development in the Territories to be carried out by the federal agency, which leaves little opportunity for investor-owned electric utility operations in Canada's north.

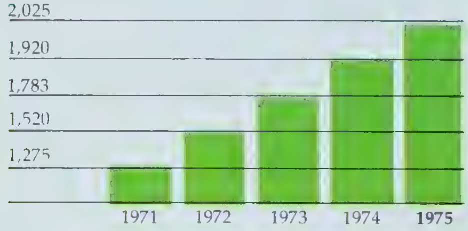
Revenues (Thousands of Dollars)



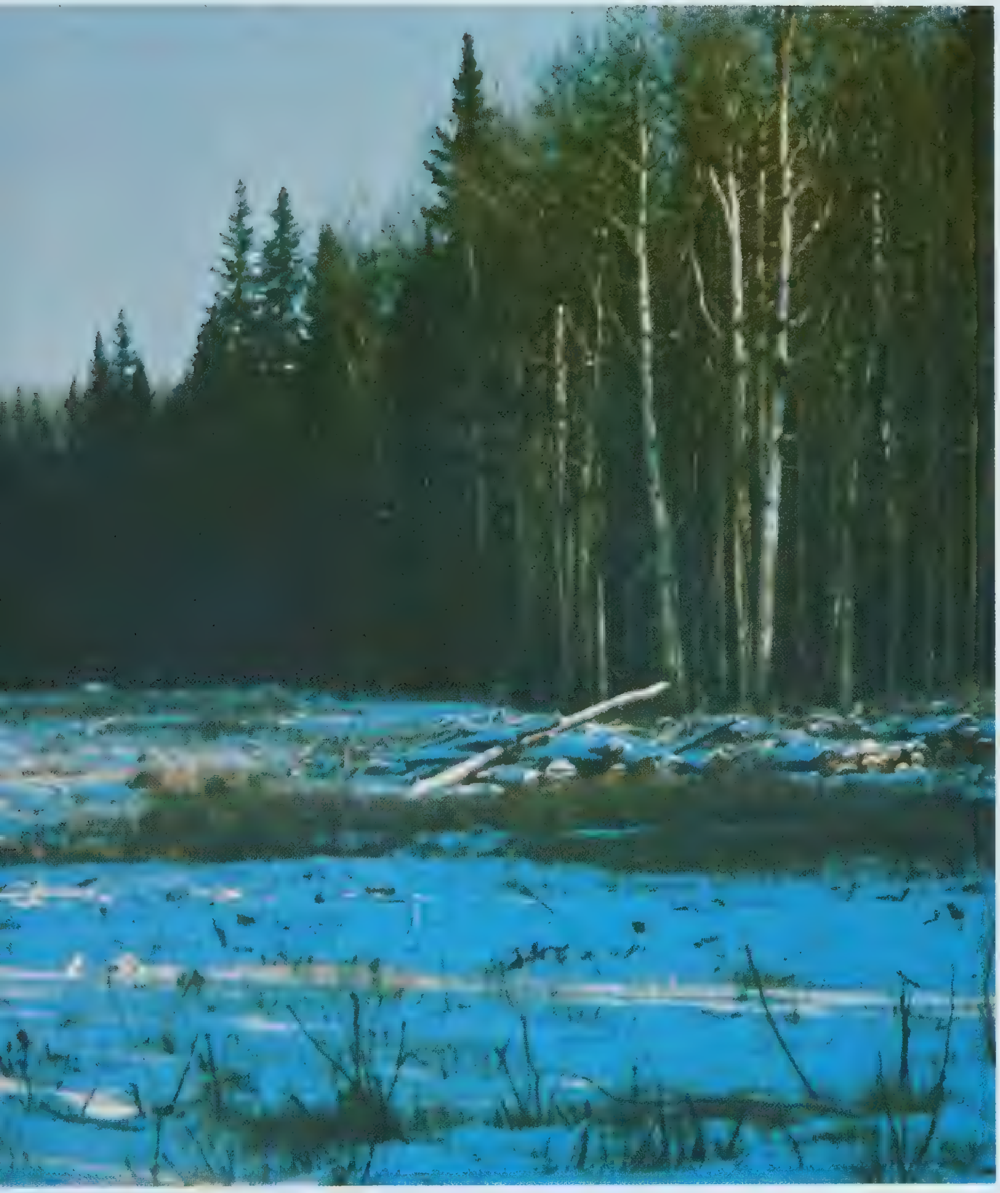
	Residential	Commercial	Industrial	REA & Other	Total
75	12,309 21%	16,971 30%	21,062 37%	6,953 12%	57,295 100%
74	9,632 21%	13,586 30%	16,759 36%	5,935 13%	45,912 100%
73	8,203 22%	12,841 34%	13,459 35%	3,401 9%	37,904 100%
72	7,612 23%	11,698 35%	11,076 33%	3,192 9%	33,578 100%
71	6,864 23%	10,735 35%	9,570 32%	3,145 10%	30,314 100%

In the chart above electric revenues include only those resulting directly from the sale of electric energy. Electric revenues per financial statements include other miscellaneous operating revenues

Sales (Millions of Kilowatt Hours)



Residential	Commercial	Industrial	REA & Other	Total
368 18%	369 18%	1,029 51%	259 13%	2,025 100%
323 17%	332 17%	1,005 52%	260 14%	1,920 100%
290 16%	320 18%	978 55%	195 11%	1,783 100%
268 18%	290 19%	779 51%	183 12%	1,520 100%
236 18%	262 21%	596 47%	181 14%	1,275 100%



High above the frozen muskeg, Alberta Power linemen work in sub-zero weather on the 200 miles of transmission line that will connect the Fort McMurray area to the Alberta Power grid. At present the area is supplied with electricity from APL's local diesel-powered generating plant.

Market Growth

The thriving economy of Alberta continues to be a dominant factor in the growth of the electric power industry in the province. Alberta's population increased about 3.2 per cent during 1975 compared to 1.5 per cent for the nation as a whole. At the same time unemployment was among the lowest of all the provinces in Canada, closing the year at 2.7 per cent seasonally adjusted compared to 7.1 per cent nationally.

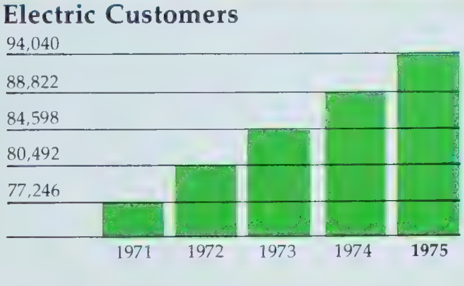
During the year the governments of Canada, Alberta and Ontario became partners in the $2 billion Syncrude oil sands project which ensures its continuance following the withdrawal of one of the original partners. The construction work force on the Syncrude site near Fort McMurray has been growing steadily and will peak at about 6,600 employees in mid-1976.

Also, Imperial Oil Limited continued to expand its pilot project to test in situ recovery methods of heavy oil deposits in the Cold Lake area. Other smaller pilot projects in this part of the province have been initiated or announced.

In the petrochemical field, the provincial government has given approval to a $280 million ethylene plant near Red Deer. The start of this project will be a decisive step in the development of a world-scale petrochemical indu:try for Alberta, and can be expected to have a positive continuing impact on the Alberta economy.

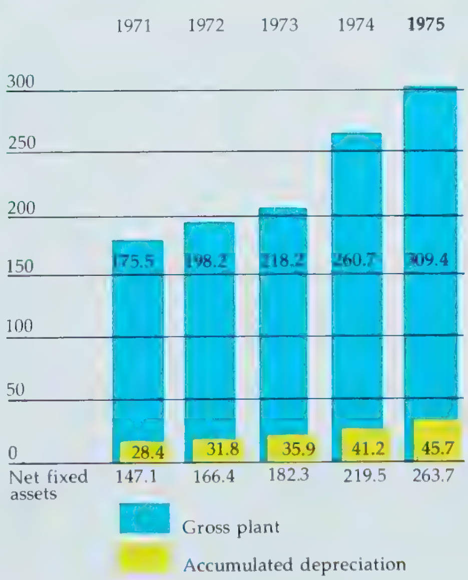
Alberta oil production declined by 11 per cent in 1975 from 1974, largely because export quotas set by the federal government and overpricing of Canadian crude in the U.S. market in the first half of 1975 forced production cutbacks. The decrease is expected to extend until the latter half of the year when completion of the Sarnia to Montreal pipeline will

Electric Customers



Resi-dential	Com-mercial	Industrial	REA & Other	Total
56,673 60%	13,574 15%	3,057 3%	20,736 22%	94,040 100%
52,406 59%	13,354 15%	2,895 3%	20,167 23%	88,822 100%
49,370 58%	13,273 16%	2,536 3%	19,419 23%	84,598 100%
46,391 57%	12,804 16%	2,173 3%	19,124 24%	80,492 100%
43,934 57%	12,490 16%	1,806 2%	19,016 25%	77,246 100%

Net Fixed Assets (Millions of Dollars)



allow the flow of 250,000 barrels per day of Alberta crude oil into the eastern Canada market. Despite production declines, energy sales to oil producers are expected to grow modestly as the energy required to produce oil increases with the fall in field pressures.

The Syncrude oil sands project and the Cold Lake development have brought rapid population growth in those parts of APL's service area. Continued activity in the oil sands deposits, all of which are located in or near areas served by APL, and completion of several agricultural product processing plants are expected to maintain the company's current market share through 1976.

Among the larger industrial facilities in the province that APL connected to its system during the year were: a rapeseed processing plant in Lloydminster; an aspen board plant at Slave Lake; the Imperial Oil pilot plant near Cold Lake; the Atlantic Richfield gas plant at Keg River; an alfalfa pelletizing plant at Falher and the Syncrude construction site. The value of building permits in the eight largest communities which APL serves increased 51 per cent during the year to $77.9 million.

The following table illustrates electrical sales to various consumer categories.

	Thousands of Kilowatt Hours	Per Cent of Total
Industrial	1,028,612	51
Commercial	369,596	18
Residential	367,908	18
REA and others	258,597	13
Total	**2,024,713**	**100**

New Construction

APL's capital expenditures for new construction projects in 1975 were $51.3 million. The 150 megawatt Battle River Unit Number Four was the largest of these projects, accounting for $26.3 million in 1975. Total expenditures on Unit Number Four to the end of the year were $60.8 million. Unit Number Four went into production on a regular basis on December 8. Further expenditures of $6 million will be required in 1976 to complete pollution control modifications required for the older units in the plant.

Preliminary engineering and studies have been initiated for a 375 megawatt Unit Number Five at Battle River. Provincial load projections indicate a requirement for this additional capacity in 1981.

The following is a summary of other major developments which took place during the year:

At Jasper, an 8400 kilowatt plant with four natural gas units was completed to replace one that was destroyed by fire in February, 1974.

Two portable 2500 kilowatt diesel generating units were added to the Fort McMurray power plant to handle the increasing load until completion of the Mitsue-Mildred Lake-Fort McMurray transmission line. This project, which will consist of 175 miles of 240 kilovolt (KV) line, 32 miles of 144 KV line and four substations, is scheduled for completion in 1976.

A transmission line from Battle River to the Calgary Power system at Nevis was converted from 144 KV to 240 KV. A similar conversion of the Wabamun-Mitsue line to 240 KV was rescheduled for the spring of 1976 because of delays in approvals.

A new transmission line from Battle River to Metiskow went into service early in 1975 at 144 KV. This line, designed for 240 KV, was built jointly with Calgary Power.

A variety of other projects were carried out throughout the system

during the year to improve transmission capacity and reliability.

During 1975 approval was received from the Energy Resources Conservation Board to decommission the 27-year-old eight-megawatt Vermilion power plant. The Fairview power plant, acquired in 1946, was also decommissioned with the remaining two 3000 kilowatt units being moved to the new Jasper power plant.

Approvals have been received from the Energy Resources Conservation Board and the Department of the Environment to install 100-kilowatt generating plants at the isolated northern Alberta communities of Peerless Lake. Trout Lake and Chipewyan Lake.

The company's total installed plant capacity increased from 523 megawatts to 686 megawatts during the year. Total coal fired capacity is now 531 megawatts.

As a result of negotiations with Manalta Coal Ltd., Alberta Power has taken over purchase of a 60-cubic yard dragline used for the strip mining of coal. The dragline is expected to be delivered in late 1976 and in operation at the Battle River location in early 1978.

Because of rapid growth in Fort McMurray, overhead wiring on the main highway to the town is installed on wooden poles as a temporary measure. This section of highway is to be widened to four lanes.

ELECTRIC SYSTEM

AREAS SERVICED BY ALBERTA POWER LIMITED

MAJOR COMPANY TRANSMISSION LINES

MAJOR COMPANY TRANSMISSION LINES UNDER CONSTRUCTION

GENERATING PLANTS

TRANSMISSION LINES OWNED BY OTHERS

Natural Gas Operations

The company's natural gas operations are conducted by two subsidiaries: Canadian Western Natural Gas Company Limited of Calgary, which serves the southern half of Alberta; and Northwestern Utilities Limited of Edmonton, which serves north-central Alberta and, through a subsidiary, Northland Utilities (B.C.) Limited, Dawson Creek and district in north-eastern British Columbia. Combined, the companies at year-end served 372,254 customers in 253 communities. A record 19,923 new customers were added during the year.

The companies produced 1975 revenues of $142,436,000 compared to $91,486,000 in the previous year. Main contributors to the revenue growth were higher rates and growth in system sales.

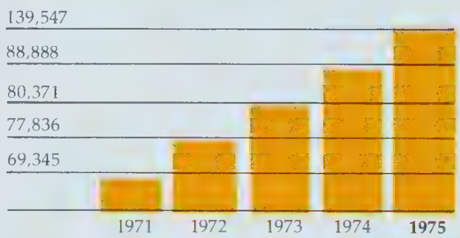
Rates

Both companies made several appearances before the Alberta Public Utilities Board during the year for rate adjustments to offset increasing operating expense due to higher gas supply costs and inflation generally.

Gas supply prices are determined, to a large extent, by the federal and Alberta governments, which, in effect, negotiate to set the field price. It is an objective of the Alberta government to permit the price of natural gas to rise in stages to its commodity value; that is, a value equivalent to that of oil in terms of energy content. This policy is intended to increase the return to the producers and provide the economic incentive to step up exploration and develop new gas reserves.

To shield the Alberta consumer from the full impact of rapid natural gas price increases, the provincial government in 1974 introduced a rebate plan under which the province pays the difference between the field price of natural gas and a "support price" set by the government. At present the field price is approximately 73 cents a thousand cubic feet and the support price on

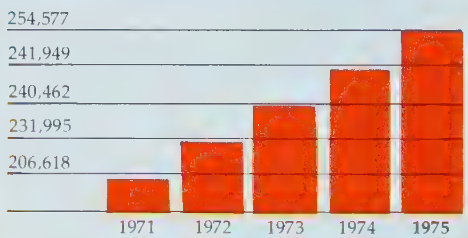
Revenues (Thousands of Dollars)



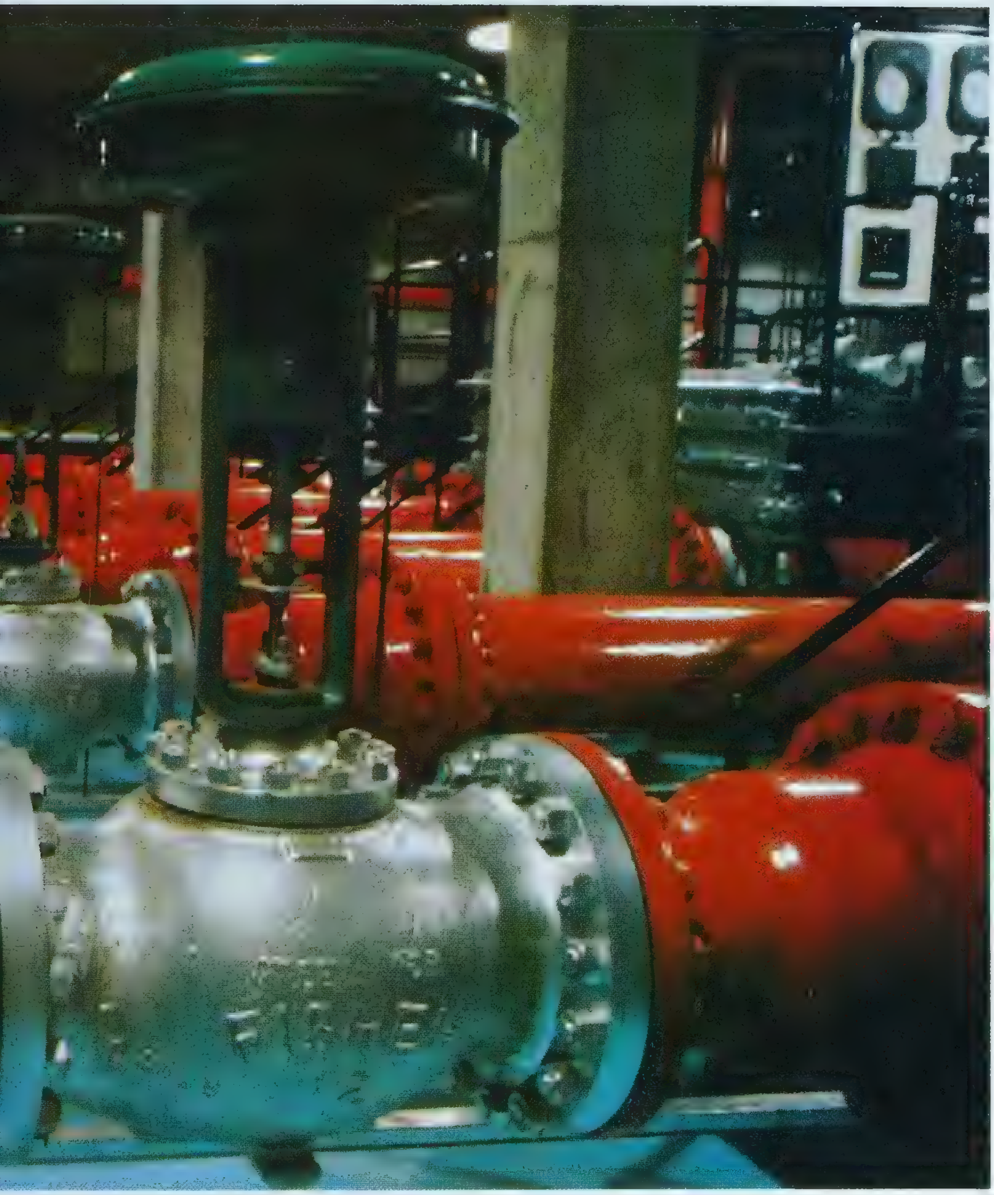
	Resi-dential	Com-mercial	Industrial	Other	Total
75	52,358 38%	37,027 27%	47,849 34%	2,313 1%	139,547 100%
74	36,503 41%	24,245 27%	27,043 31%	1,097 1%	88,888 100%
73	34,034 42%	22,511 28%	22,888 29%	938 1%	80,371 100%
72	34,123 44%	22,656 29%	20,278 26%	779 1%	77,836 100%
71	30,932 45%	20,201 29%	17,556 25%	656 1%	69,345 100%

In the chart above natural gas revenues include only those resulting directly from the sale of natural gas. Natural gas revenues per financial statement, include other miscellaneous operating revenues

Sales (Millions of Cubic Feet)



Resi-dential	Com-mercial	Industrial	Other	Total
69,033 27%	68,585 27%	110,480 43%	6,479 3%	254,577 100%
64,051 26%	64,622 27%	107,081 44%	6,215 3%	241,949 100%
61,934 26%	61,657 26%	110,930 46%	5,941 2%	240,462 100%
63,656 27%	62,244 27%	101,053 44%	5,042 2%	231,995 100%
57,472 28%	55,691 27%	89,153 43%	4,302 2%	206,618 100%



Up to 300 million cubic feet of gas a day will pass through Northwestern's No. 1 Gate Station in Edmonton during a period of peak demand.

April 1, 1976 was raised from 28 cents to 56 cents a thousand cubic feet. In 1975 the rebate program protected the gas companies' customers from $60.5 million in gas supply costs.

In addition to gas supply, costs of supplies, materials, wages and the cost of borrowing for capital investment have increased substantially during the past two years.

Gas Rate Developments

August 1, 1974 (CWNG)

Interim rate increase becomes effective resulting in $2.7 million of additional revenue in 1974 and a further $6 million in 1975.

January 1, 1975 (NUL)

The first rate increase in 15 years becomes effective on an interim basis providing additional 1975 revenues of $6 million.

June 1, 1975 (NUL)

Rate increase granted to cover higher federal income taxes now payable on provincial royalties on gas production from company's owned reserves. Additional revenue: $1.6 million.

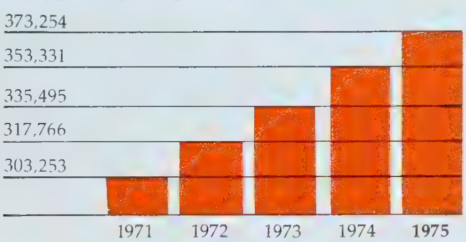
July 1, 1975 (CWNG) (NUL)

Both companies are granted rate increases to recover higher gas supply costs resulting from the increase in the provincial government support price from 16.7 cents to 28 cents per thousand cubic feet effective April 1, 1975; higher royalty expense on production from company-owned reserves; and higher transportation expense paid to suppliers. Additional revenues generated for Canadian Western Natural Gas - $4.8 million; Northwestern Utilities - $13.4 million.

July 5, 1975 (CWNG)

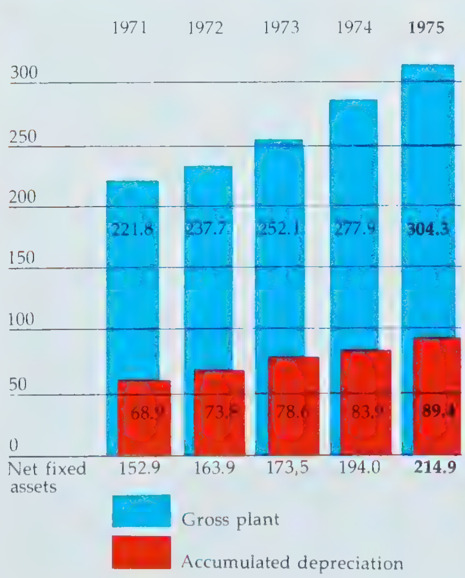
The Public Utilities Board (PUB) gives final approval to interim rates which had become effective in August 1974. At the same time the board approved the July 1, 1975 interim increase.

Natural Gas Customers



Residential	Commercial	Industrial & Other	Total
336,064 90.0%	36,648 9.8%	542 0.2%	373,254 100%
317,535 89.9%	35,286 10.0%	510 0.1%	353,331 100%
301,084 89.7%	33,874 10.1%	537 0.2%	335,495 100%
284,764 89.6%	32,513 10.2%	489 0.2%	317,766 100%
271,416 89.5%	31,377 10.3%	460 0.2%	303,253 100%

Net Fixed Assets (Millions of Dollars)



September 1, 1975 (CWNG)

Interim increase granted to meet inflationary rises in operating expenses. Additional revenues generated in 1975: $3.4 million.

September 15, 1975 (NUL)

The PUB gives final approval to revenue increase requests of Jan. 1, June 1 and July 1, 1975.

October 1, 1975 (NUL)

PUB grants interim increase to meet inflationary increases in operating expenses. Additional revenues generated in 1975: $2.3 million.

November 16, 1975 (NUL)

Rates to City of Edmonton consumers increase 2.5 per cent to recover rise in Edmonton franchise tax rate. Additional revenues generated: $ 2 million.

Since 1974 residential gas rates have approximately doubled, but the net earnings of the companies have only increased by an amount necessary to maintain sufficient earnings on invested capital to allow financing of the record levels of new facility construction.

Sales

Sales volume of natural gas rose in 1975 by five per cent to 255 billion cubic feet. The largest increase was recorded by residential customers whose consumption went up eight per cent (five billion cubic feet) over the previous year.

The volume of natural gas sold by type of customer is shown in the following table:

	Billions of Cubic Feet	Per Cent of Total
Residential	69	27
Commercial	69	27
Industrial	117	46
Total	**255**	**100**

Gas Supply

The cost of the companies' gas supply rose to $70,852,000 in 1975 from $40,179,000 in 1974. These figures do not include gas supply costs sheltered by the provincial government's Natural Gas Rebates Plan.

As a result of federal and provincial legislation and the federal/provincial agreement on gas pricing ,all Alberta gas producers receive a pro rata share of revenues generated by the differential in price between gas exported to the United States and that marketed in Canada. As gas producers, Canadian Western and Northwestern are participating in this "border flow back". While it is the intention of the companies to use these funds for exploration of natural gas reserves, such disposition is subject to approval by the Public Utilities Board.

The following table shows the relative volumes of gas obtained from various supply sources in 1975:

	Per Cent of Total
Oilfield and Gas Plants	42
Dry Gas Fields	31
Export Companies	24
Pipeline Companies	3
	100

The Northwestern system obtained 25 per cent of its annual requirements from company-owned reserves in Viking-Kinsella, Beaverhill Lake, Fort Saskatchewan, Fairydell-Bon Accord and other dry gas fields. Canadian Western's dry gas storage reservoirs at Carbon and Bow Island were capable of supplying 33 per cent of its total system demand.

During the year contracts were negotiated for 330 billion cubic feet of new gas supplies, the majority of which was in the Arrowwood and Dixonville areas. To ensure maximum security of gas supply and the development of additional reserves in fields where gas is currently purchased, most existing supply contracts have been renegotiated. The price paid producers currently averages 73 cents per thousand cubic feet, plus border flow back.

During 1975 the companies also purchased 64 billion cubic feet of gas under its contracts with the export companies.

The gas companies are continuing their practice of contracting for economic supplies of gas directly with the producers, of developing company-owned reserves, and of pursuing a program of acquisition and development of additional gas properties. During 1975 the companies drilled two new wells, one of which was proved successful.

Both companies have discontinued their participation in the Gas Arctic - Northwest Project Study Group, the consortium of companies planning to build a gas pipeline from the Arctic to Canadian and U.S. markets. This action followed a Public Utilities Board decision to disallow the costs of taking part in the project in rate base calculations.

New Construction

Capital expenditures by the gas utilities in 1975 were $30 million compared to $27 million in 1974. The abnormally high rate of inflation, reflected in the cost of labor, steel, plastic pipe and other materials, was a major factor in the increased construction expenditure.

A major project during the year was the completion of the second phase of Northwestern's Homeglen-Rimbey to Edmonton transmission line. This 25 miles of 24-inch line will provide additional capacity to meet peak requirements in the 1975-76 winter season. Canadian Western built 21 miles of 8-inch line to tie in additional gas reserves in the Arrowwood area.

Expenditures on the distribution system were $19.7 million, primarily to enable the existing system to handle the record number of new customers. Other expenditures were required for additions to service facilities and equipment.

Market Growth

A major event during 1975 was the renegotiation of the franchise agreement between the City of Edmonton and Northwestern Utilities for a further ten-year term. Northwestern has served Edmonton since the company was established in 1923.

Market growth is reflected in the amount of new construction taking place in the province. Building permits valued at $859 million were issued in 1975 in Alberta's principal cities of Calgary, Edmonton, Lethbridge and Red Deer, maintaining the brisk development pace set in the previous year.

In Calgary $393 million worth of

construction projects were initiated, up notably from 1974's $273 million.

Edmonton processed building permits valued at $396 million in 1975, the second consecutive year that construction in the capital city has exceeded $300 million.

Lethbridge and Red Deer launched projects valued at $43.6 million and $26.5 million respectively, both topping their 1974 performances.

Outside the cities, the gas companies have continued to participate in the Alberta government's rural gas program, adding a record 1,909 new customers during the year. The aim of this program is to bring natural gas service to the majority of rural Alberta householders.

With more than $1 billion worth of petrochemical projects underway or planned in the province, and the Alberta government committed to orderly economic growth and diversification, the gas utility operations appear to face vigorously expanding markets for their services throughout 1976 and beyond. In light of the potential for growth in Alberta, the company considers that increasing caution should be exercised in the granting of permits for additional exports of gas so that the traditional protection to Alberta consumers is maintained.

Continuing growth of Edmonton's downtown core requires constant upgrading and expansion of Northwestern's distribution facilities.

NATURAL GAS SYSTEM

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

NORTHWESTERN UTILITIES LIMITED

MAJOR COMPANY PIPELINES

MAJOR PIPELINES OWNED BY OTHERS

Rate Review

Alberta's enlightened approach to rate regulation has spared the province's utility companies most of the serious regulatory problems that have handicapped utility operations in many other jurisdictions in North America. One such problem is the lag which can occur between the time a rate increase is applied for and when it is granted.

The Alberta Public Utilities Board has for a number of years permitted interim rates, which are normally granted promptly and for the full amount applied for, once the need is clearly demonstrated. They are subject to confirmation or refund at a later date after public hearings and the board's final decision. This practice enables the company to protect itself from earnings attrition caused by sudden and unforeseen cost rises that are beyond the company's control.

Another major feature of Alberta's regulatory process is the use of a future test year rather than a historical test year as is generally the practice elsewhere. For example, the three rate increase applications filed and approved on an interim basis during 1975 were designed to recover increased costs expected for the year and provide a fair return on forecast rate base for that year. Revenue-requirement and cost-of-capital computations also anticipated the new common share issue which took place in 1975 and, therefore, the new issue did not dilute earnings per share.

To help expedite proceedings, the board has introduced guidelines for the conduct of hearings and, by use of a pre-hearing conference with the applicant and the intervenors, establishes those issues which are of particular interest to the parties involved. The admission of written evidence and the opportunity for intervenors to question the company and obtain additional information prior to hearings also help save time in public hearings and contribute to a regulatory system that is more efficient and more immediately responsive to the needs of the regulated companies and the public.

The board clearly recognizes the periodic need for investor-owned utilities to go to the equity markets for essential new capital and the consequent importance of maintaining investor confidence in the financial integrity of the utilities. Investor confidence is understood to translate into a market price for common shares that will accommodate new issues at prices that will not dilute present shareholders' equity.

The regulatory process is severely tested during a period of very high levels of inflation. The features of the process in Alberta, some of which have been in place for a number of years, have now proved to be of particular merit. Any abatement in the level of inflation should serve to reduce the pressure for rate relief and lighten the load that has fallen on the regulators, the regulated companies and the intervenors in recent years.

The following tables summarize the outcome of rate cases filed by CU companies during 1974-75.

1975 RATE APPLICATIONS	Alberta Power	Canadian Western	Northwestern Utilities
Date application filed	July 2	July 25	Aug. 25
Interim rates approved by PUB effective	Aug. 1	Sept. 1	Oct. 1
Return on equity for equity component of rate base	14.3%	15.0%	14.8%

FINAL PUB DECISIONS ON 1974 APPLICATIONS	Alberta Power	Canadian Western	Northwestern Utilities
1975 utility income ($ millions) requested and granted	17.9	7.7	10.2
Increase in revenues	19.3%	38.4%	43.3%
Date decision received	Aug. 1975	Apr. 1975	Sept. 1975
Interims granted	June 1974	Aug. 1974	Jan. 1975

Financial Review and Statements

Financial Review and Statements

Revenues and Earnings

Inflationary pressures on costs of construction, operation and on financing of the company required prompt regulatory action on requests for increased rates during the year. While the volume of business increased five per cent for sales of both natural gas and electric energy, total revenues of the company in 1975 rose $62.6 million or 45 per cent above the level recorded in the previous year. Nearly half this increase in revenues was required to meet higher costs of natural gas supply. Other operating and financial costs absorbed all but $6.3 million of the remaining increase in revenues.

Net earnings from operations available to common shareholders were $18.8 million in 1975, $6.3 million greater than in 1974. Expressed on a fully diluted per share basis, this represents $1.45 on a greater number of shares outstanding in 1975, compared to $1.05 in the previous year. Near average temperature conditions were experienced in both years.

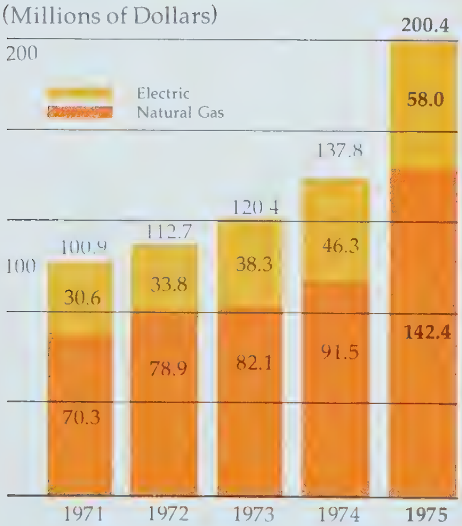
Since the restructuring of the company in 1972, net fixed assets have grown from $300 million (December, 1971) to $478 million (December, 1975) or 59 per cent. Fully diluted net earnings per common share, excluding extraordinary items, have increased from 91 cents (1971) to $1.45 (1975), also a gain of 59 per cent.

SOURCE OF NET EARNINGS FROM OPERATIONS

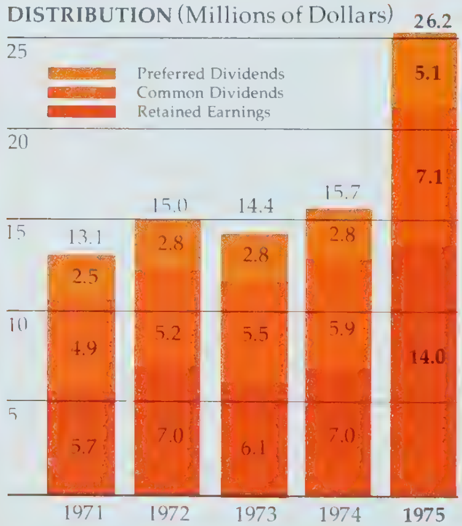
	1975	1974	1973	1972	1971	Four-Year Compound Growth Rate
	(Thousands of Dollars)					
Electric	**13,567**	7,623	7,467	7,415	6,038	22.4%
Gas	**10,927**	8,240	8,006	8,563	8,083	7.8%
Eliminations upon consolidation	**231**	257	(238)	115		
TOTAL	**24,725**	16,120	15,235	16,093	14,121	
Minority interest and preferred dividends paid to minority shareholders	**860**	860	860	962	1,226	
CONSOLIDATED NET EARNINGS FROM OPERATIONS	**23,865**	15,260	14,375	15,131	12,895	16.6%

1975 REVENUE DOLLAR

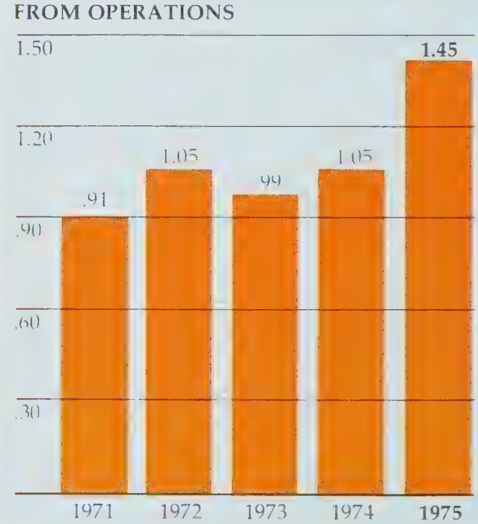
REVENUES (Millions of Dollars)



NET EARNINGS AND EARNINGS DISTRIBUTION (Millions of Dollars)



FULLY DILUTED EARNINGS PER SHARE FROM OPERATIONS



Capitalization and New Financing

During the year the company continued to obtain funds in the money market by issues of notes payable and through lines of bank credit, which are maintained at a level of $60 million, of which $12.7 million was unused at year-end.

The continued rapid growth in assets cannot be financed solely from funds internally generated. Substantial new capital, in the form of both debt and equity, is required. Two equity issues were arranged in the year with $30 million of 10¼% preferred shares issued early in 1975 and 1.1 million shares of common stock issued in November at a price of $9.25 a share. Retained earnings also increased by $13.1 million in the year. The resulting addition of over $50 million in equity capital in 1975 has significantly improved the distribution of capital employed. At December 31, 1975, the capital structure was as follows:

	$ Millions	%
Notes payable and long-term debt	231.9	53
Preferred equity (including minority interest)	59.3	14
Common equity (including $1.25 convertible preferred shares)	146.6	33
	$437.8	100%

On January 14, 1976, an agreement with underwriters was arranged for the sale of $50 million principal amount of 11¼% debentures. This issue, the largest security issue offered to date, was well received and significantly increases the number of individuals and institutions holding debt securities of the company.

Income Taxes

The provision for income taxes increased by $6.3 million to $8.7 million in 1975 as the effective rate of tax on earnings from operations increased from 13 per cent in 1974 to 26 per cent. Changes in tax legislation in the year increased the level of taxes payable by the gas utility subsidiaries. The practice of claiming maximum capital cost allowances in determining the provision for income taxes resulted in an abnormally low provision in 1974 for the electric utility subsidiary.

Government of Alberta Natural Gas Rebates Plan

The natural gas supply costs borne by customers of the company amounted to $70.9 million in 1975, compared to $40.2 million in 1974. However, the Alberta government Natural Gas Rebates Plan shielded consumers from $60.5 million of natural gas supply costs representing 46 per cent of the gross costs of natural gas supply incurred by the company and recovered from the provincial government under this program. In 1974, 27 per cent of natural gas supply costs were underwritten by the rebates plan.

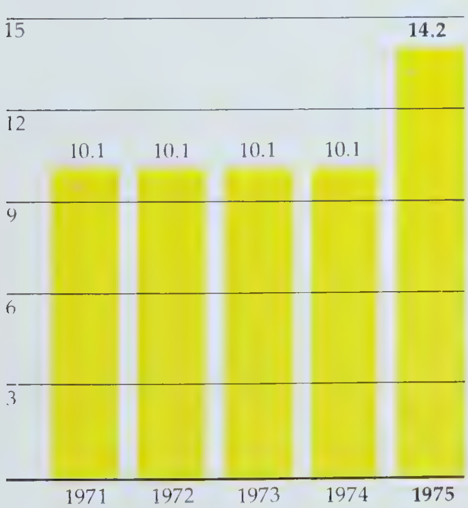
Assets and Capital Expenditures

Total assets of the company on December 31, 1975 were $574 million, an increase of nearly $100 million over year-end 1974. Capital expenditures in the year were a record total of $81 million, 13 per cent above the 1974 expenditures of $72 million. In 1976, a year that will require no major outlays on new generating plant, the forecast expenditures are $79 million.

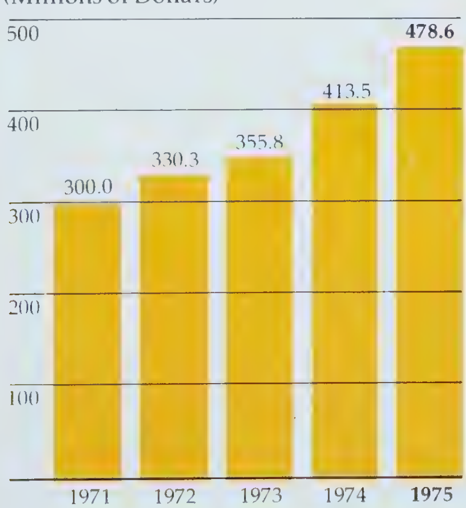
Shares and Shareholder Distribution

At the end of 1975, there were 14,198,376 common shares outstanding and 261,284 shares of $1.25 preferred equity which are convertible into 522,568 common shares. The number of common shareholders increased from 1,595 at the close of 1974 to 3,283 at the close of 1975, reflecting the conversion of $1.25 preferred shares and the issue of common shares in the year.

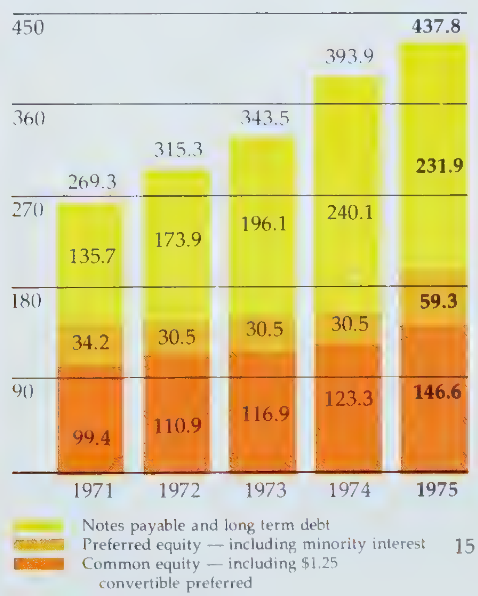
COMMON SHARES OUTSTANDING



NET FIXED ASSETS
(Millions of Dollars)



CAPITALIZATION
(Millions of Dollars)



Consolidated Statement of Earnings

Year ended December 31, 1975 with comparative figures for 1974

	Thousands 1975	1974
NATURAL GAS REVENUES	**$142,436**	$ 91,486
ELECTRIC REVENUES	**57,945**	46,295
	200,381	137,781
OPERATING EXPENSES (NOTE 1)		
Natural gas supply (Net of Alberta Government Rebate)	**70,852**	40,179
Operating and maintenance	**56,541**	43,572
Taxes — other than income	**11,804**	8,035
Depreciation	**13,293**	12,906
	152,490	104,692
OPERATING INCOME	**47,891**	33,089
OTHER INCOME		
Interest capitalized during construction	**4,022**	1,601
Interest and dividends	**417**	223
Gain on purchase of long-term debt	**405**	286
Miscellaneous	**527**	464
	5,371	2,574
	53,262	35,663
INCOME DEDUCTIONS		
Interest on long-term debt	**15,446**	13,902
Interest on loans from parent and affiliated companies	**263**	262
Other interest	**3,852**	2,691
Debt discount and expense amortized	**290**	272
	19,851	17,127
	33,411	18,536
INCOME TAXES (NOTE 2)	**8,686**	2,416
	24,725	16,120
MINORITY INTERESTS	**860**	860
NET EARNINGS BEFORE EXTRAORDINARY ITEMS	**23,865**	15,260
EXTRAORDINARY ITEMS — NON-RECURRING GAINS (NOTE 3)	**2,329**	444
NET EARNINGS	**$ 26,194**	$ 15,704
EARNINGS — DOLLARS PER COMMON SHARE (NOTE 4)		
Basic		
Net earnings before extraordinary items	**$ 1.69**	$ 1.24
Extraordinary items — non-recurring gains	**.21**	.04
Net earnings	**$ 1.90**	$ 1.28
Fully diluted		
Net earnings before extraordinary items	**$ 1.45**	$ 1.05
Extraordinary items — non-recurring gains	**.16**	.03
Net earnings	**$ 1.61**	$ 1.08

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

CANADIAN UTILITIES LIMITED

Consolidated Balance Sheet

December 31, 1975 with comparative figures for 1974

	Thousands 1975	1974
ASSETS		
CURRENT ASSETS		
Cash	$ 365	$ 36
Marketable securities — at cost		522
Accounts receivable (Note 5)	61,885	33,248
Materials and supplies — at average cost	10,078	9,546
Prepaid expenses (Note 6)	4,112	1,699
	76,440	45,051
TRUST ASSETS HELD FOR RURAL CO-OPERATIVE LINES, PER CONTRA	6,726	6,572
TRUST ASSETS HELD FOR INCOME TAX REBATE FOR CONSUMERS, PER CONTRA	3,056	2,153
ACCOUNTS RECEIVABLE DUE BEYOND ONE YEAR	1,051	1,394
PROPERTY, PLANT AND EQUIPMENT AT COST (NOTE 7)	613,632	538,665
Accumulated depreciation	135,042	125,191
	478,590	413,474
UNAMORTIZED DEBT DISCOUNT AND DEFERRED EXPENSES (NOTE 8)	7,485	6,365
GOODWILL	518	533
	$573,866	$475,542
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Due to bank	$ 4,124	$ 6,057
Accounts payable and accrued liabilities	63,212	37,204
Dividends payable	1,015	
Long-term debt — current maturities (Note 10)	11,578	4,252
Preferred shares to be redeemed (Note 13)	1,200	
Deposits	1,742	1,521
Income and other taxes	12,969	3,530
	95,840	52,564
AMOUNTS HELD IN TRUST, PER CONTRAS	9,782	8,725
MISCELLANEOUS LIABILITIES	1,394	1,011
NOTES PAYABLE (NOTE 9)	47,275	42,078
NOTE PAYABLE TO AFFILIATED COMPANY, 7½%, due November 15, 1978	3,500	3,500
LONG-TERM DEBT (NOTE 10)	181,068	194,535
DEFERRED INCOME TAXES (NOTE 2)	954	1,187
CONTRIBUTIONS FOR EXTENSIONS TO PLANT	27,641	18,110
AMOUNT RECEIVED UNDER NATURAL GAS PRICING AGREEMENT ACT (NOTE 11)	478	
MINORITY INTERESTS (NOTE 12)	20,008	20,008
SHAREHOLDERS' EQUITY (NOTE 10)		
Preferred shares (Note 13)	44,526	45,953
Common shares (Note 14)	105,833	65,429
	150,359	111,382
Less excess value of shares of subsidiary companies over underlying net book value at December 31, 1971	17,567	17,567
	132,792	93,815
Retained earnings	53,134	40,009
	185,926	133,824
	$573,866	$475,542

On behalf of the Board:

J. E. Maybin / Director **E. W. King** / Director

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Statement of Changes in Financial Position

Year ended December 31, 1975 with comparative figures for 1974

	Thousands 1975	1974
SOURCES OF WORKING CAPITAL		
Net earnings before extraordinary items	**$ 23,865**	$ 15,260
Add non-cash items, principally depreciation	**14,729**	13,631
Provided from operations	**38,594**	28,891
Increase in notes payable	**5,197**	42,078
Note payable to affiliated company		3,500
Issue of long-term debt		31,971
Issue of 10¼% cumulative redeemable second preferred shares series A	**28,973**	
Issue of common shares	**9,465**	
Issue of common shares on conversion of $1.25 preferred shares	**30,229**	105
Increase in contributions for extensions to plant	**9,916**	3,673
Disposition of property, plant and equipment	**3,943**	1,669
Extraordinary disposition of property, plant and equipment	**2,572**	1,048
	128,889	112,935
USES OF WORKING CAPITAL		
Purchase of property, plant and equipment	**82,981**	72,888
Reduction in long-term debt	**13,467**	5,477
Redemption of preferred shares	**1,200**	
Dividends paid — preferred	**5,075**	2,781
— common	**7,142**	5,943
Preferred dividends declared in advance	**141**	
Conversion of $1.25 preferred shares	**30,229**	105
Increase in deferred expenses	**1,282**	1,686
Other	**(741)**	812
	140,776	89,692
INCREASE (DECREASE) IN WORKING CAPITAL	**$(11,887)**	$ 23,243
ANALYSIS OF CHANGES IN WORKING CAPITAL		
Cash	**$ 329**	$ (466)
Marketable securities	**(522)**	
Accounts receivable	**28,637**	17,757
Materials and supplies	**532**	4,233
Prepaid expenses	**2,413**	1,165
Total	**31,389**	22,689
Due to bank	**(1,933)**	(20,416)
Accounts payable and accrued liabilities	**26,008**	21,020
Dividends payable	**1,015**	
Owing to parent		(3,564)
Long-term debt — current maturities	**7,326**	2,010
Preferred shares to be redeemed	**1,200**	
Deposits	**221**	348
Income and other taxes	**9,439**	48
Total	**43,276**	(554)
INCREASE (DECREASE) IN WORKING CAPITAL	**$(11,887)**	$ 23,243

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Statement of Retained Earnings

Year ended December 31, 1975 with comparative figures for 1974

	Thousands 1975	1974
BALANCE AT BEGINNING OF YEAR	**$ 40,009**	$ 33,595
ADD NET EARNINGS	**26,194**	15,704
	66,203	49,299
DEDUCT		
Dividends		
5% cumulative redeemable preferred shares	**200**	200
Cumulative redeemable preferred shares		
4¼% series	**64**	64
6% series	**300**	300
$1.25 cumulative redeemable convertible preferred shares	**1,701**	2,217
10¼% cumulative redeemable second preferred shares series A	**2,810**	
Common shares	**7,142**	5,943
	12,217	8,724
Preferred dividends declared in advance	**141**	
Provision for taxes on 1971 undistributed income on hand		566
Commission and expenses on issue of common shares	**711**	
	13,069	9,290
BALANCE AT END OF YEAR	**$ 53,134**	$ 40,009

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Summary of Significant Accounting Policies

Basis of consolidation

The consolidated financial statements include the accounts of the company and all subsidiary companies. All material inter-company balances and transactions have been eliminated.

Property, plant and equipment

Property, plant and equipment includes cost of land, buildings and equipment. Certain additions to property, plant and equipment are made with the assistance of provincial government grants and cash contributions from the customers who are to be served by the specific additions. Such contributions are required where the estimated revenue, over a specific period of time, is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. The gross cost of additions including any allowance for funds used during construction is included in property, plant and equipment.

Depreciation is provided on pooled assets at composite rates on a straight line basis over the average estimated useful lives of the assets. This is in accordance with the orders of regulatory bodies. Effective rates are approximately 3% per annum on the gross plant net of contributions for extensions with the exception of certain resource properties which are depreciated in part on a unit withdrawal basis.

On retirement of depreciable plant, the accumulated depreciation is charged with the cost of the retirement unit less net salvage. Gains and losses on extraordinary retirements are recognized as extraordinary items in the financial statements.

Interest capitalized during construction

An allowance for funds used during construction of electric plant is capitalized at the weighted average interest rate of long-term debt.

Unamortized debt discount and deferred expenses

Expenses incurred in connection with the issue of long-term debt and preferred shares are amortized over the periods that the debt and shares are outstanding.

The company became a participant in the Gas Arctic-Northwest Project Study Group on September 26, 1973. Following a decision of the Public Utilities Board of Alberta that Canadian Western Natural Gas Company Limited could not include the costs of its participation in the calculation of its rate base, the company withdrew from the group on May 31, 1975. Subsequently the Board made a similar decision with respect to Northwestern Utilities Limited.

These costs have been deferred until the feasibility of the project has been determined and the necessary regulatory approvals obtained. If the project is approved by the National Energy Board and other regulatory bodies, the group agreement provides that the participants, including participants which have withdrawn from the group, will sell the information and knowledge resulting from the study to one or more pipeline companies incorporated for the purpose of implementing the project for a price at least equal to the costs incurred and also provides that they shall have an opportunity to acquire an equity interest in the

pipeline companies. In the event the project does not proceed, costs not recovered will be written off in the statement of earnings.

Deferred charges relating to gas exploration include all expenditures related to the development of gas reserves. Costs resulting in a successful venture are capitalized and depreciated on a unit of production method. Where no economic reserves are located, costs are charged to operations.

Goodwill

Goodwill consists of the excess value of shares issued over the underlying net book value of shares acquired in 1972 from minority shareholders of a subsidiary company and is being amortized over a period of 40 years.

Income taxes

In fixing rates, except for the matters referred to in the succeeding paragraph, the Public Utilities Board of Alberta permits the utility companies to recover only taxes payable currently and, accordingly, to the extent that capital cost allowances are claimed in excess of the depreciation recorded in the accounts, there has been a related reduction in the amount of income taxes otherwise payable.

However, the gas subsidiaries are permitted to claim deferred income taxes in respect to the acquisition of natural gas rights. At the specific request of the major communities served they have agreed, with effect from January 1, 1967, to amortize such deferred taxes by reducing the annual provisions for income taxes over a ten year period. Since 1973 the gas subsidiaries have recorded deferred income taxes arising from expenses in connection with the Gas Arctic-Northwest Project Study Group, as referred to in Note 8, and at December 31, 1975 have recorded current deferred income taxes with respect to increased gas costs to be recovered from customers in 1976.

Natural gas supply

The Province of Alberta enacted The Natural Gas Rebates Act effective January 1, 1974 to shelter the majority of Alberta natural gas customers from the full impact of significant price increases for natural gas. Under the provisions of the act, which is subject to review in March, 1977, the province reimburses the gas utilities for the excess of the price paid to their suppliers over the support price established by the province. The financial statements reflect the net cost of natural gas (Note 1) and the recoverable portion over the support price is recorded as a receivable from the province (Note 5).

Notes to Consolidated Financial Statements

1. Operating expenses

	1975		1974	
	Natural Gas	**Electric**	Natural Gas	Electric
Natural gas supply:				
Gross cost of natural gas purchased	**$131,398,000**		$54,707,000	
Alberta Government rebate	**60,546,000**		14,528,000	
Net cost of natural gas purchased	**70,852,000**		40,179,000	
Operating and maintenance	**31,434,000**	**$25,107,000**	22,589,000	$20,983,000
Taxes — other than income	**9,601,000**	**2,203,000**	6,218,000	1,817,000
Depreciation	**6,931,000**	**6,362,000**	6,533,000	6,373,000
	$118,818,000	**$33,672,000**	$75,519,000	$29,173,000
Total	**$152,490,000**		$104,692,000	

2. Income taxes

The provision for income taxes in the consolidated statement of earnings includes deferred taxes of $1,321,000 in 1975 ($627,000 in 1974).

Total deferred income taxes increased by $7,706,000 during 1975 ($5,184,000 in 1974). The cumulative amount of deferred income taxes to December 31, 1975 is $38,580,000 of which $954,000 has been recorded in the accounts as a deferred credit, $1,621,000 as a reduction in deferred expenses and $1,595,000 is included in income and other taxes payable.

3. Extraordinary items

The extraordinary items amounting to $2,329,000 in 1975 and $444,000 in 1974, net of income taxes of $418,000 and $33,000 respectively, represent non-recurring gains from the sale of property in 1975 and certain utility distribution facilities in 1974.

4. Earnings per common share

In the fully diluted earnings per common share calculation, the assumption is made that warrants for the purchase of 595,000 common shares at $9 had been exercised at the beginning of each year and that the funds derived there-

from had been invested to produce an annual rate of 8% before applicable income taxes. In addition, the calculation assumes conversion of the convertible preferred shares at the beginning of each year.

If the conversion of the $1.25 Cumulative Redeemable Convertible Preferred Shares had taken place at the beginning of the year the adjusted basic earnings per share for 1975 would have been $1.53 before extraordinary items or $1.71 per share after extraordinary items.

5. Accounts receivable

	1975	1974
Consumer accounts, gas and electric	**$31,300,000**	$13.661.000
Receivable from the Province of Alberta under the Natural Gas Rebates Act	**13,321,000**	11,839,000
Other receivables and deposits	**17,264,000**	7,748,000
Balance at end of year	**$61,885,000**	$33,248,000

6. Prepaid expenses

	1975	1974
Deferred purchase gas supply costs	**$3,301,000**	$1,151,000
Other	**811,000**	548,000
Balance at end of year	**$4,112,000**	$1,699,000

7. Property, plant and equipment

	1975		1974	
	Cost	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Gas utility plant and equipment	**$295,532,000**	**$ 89,365,000**	$268,936,000	$ 83,945,000
Electric utility plant and equipment	**308,621,000**	**45,677,000**	260,046,000	41,246,000
Undertakings, franchise and gas rights	**8,000,000**		8,000,000	
Land	**1,479,000**		1,683,000	
Balance at end of year	**$613,632,000**	**$135,042,000**	$538,665,000	$125,191,000

8. Unamortized debt discount and deferred expenses

	1975	1974
Unamortized debt discount and expense	**$3,327,000**	$3,623,000
Unamortized preferred share issue expense	**1,027,000**	
Expenditures in Gas Arctic-Northwest Project Study Group (Net of accumulated deferred taxes of $1,454,000 at December 31, 1975 and $1,251,000 at December 31, 1974.)	**1,659,000**	1,380,000
Other deferred charges Unamortized expense incurred in connection with corporate reorganization, gas exploration and utility rate hearings (Net of accumulated deferred taxes of $167,000 at December 31, 1975). These charges are subject to amortization over varying periods of time, not exceeding 40 years.	**1,472,000**	1,362,000
Balance at end of year	**$7,485,000**	$6,365,000

9. Notes payable

In common with most public utilities, the company is required to obtain new capital by issues of debentures and capital stock in order to finance its construction and expansion program. To permit the company to time the issues most advantageously, the company has entered into a loan agreement with its bankers under which they are committed until March 14, 1977 to loan the company on demand up to $60,000,000. The company issues commercial paper relying upon this commitment and, accordingly, at December 31, 1975 notes payable of $47,275,000 representing commercial paper with maturities to March 31, 1976 and bank loans, have been classified as long-term debt.

10. Long-term debt

	Total	Current Maturities
Canadian Utilities Limited:		
$8^3/_8$% debentures 1972 Series, due March 1, 1992	**$29,085,000**	
$8^3/_4$% debentures 1973 Series, due July 2, 1993	**15,000,000**	
$9^1/_8$% debentures 1974 Series, due March 15, 1994	**15,000,000**	
$11^1/_2$% debentures 1974 - 2nd Series, due October 1, 1994	**17,500,000**	
	76,585,000	
Alberta Power Limited:		
First mortgage sinking fund bonds:		
Series D - $4^1/_4$%, due November 1, 1979	**3,360,000**	$ 40,000
Series E - $4^1/_8$%, due April 1, 1981	**3,001,000**	6,000
Series F - $5^1/_2$%, due December 1, 1986	**5,000,000**	
Series G - $5^5/_8$%, due June 1, 1990	**12,000,000**	
Series H - $6^1/_2$%, due February 1, 1992	**8,000,000**	
Sinking fund debentures:		
Series A - $7^1/_4$%, due May 15, 1988	**13,751,000**	1,000
Series B - $9^5/_8$%, due December 15, 1991	**8,656,000**	106,000
Series C - 8%, due June 1, 1976	**10,000,000**	10,000,000
	63,768,000	10,153,000
Canadian Western Natural Gas Company Limited:		
First mortgage sinking fund bonds:		
Series B - $5^3/_4$%, due February 1, 1982	**3,706,000**	
Series C - $5^3/_8$%, due April 1, 1983	**2,599,000**	44,000
Series D - $5^5/_8$%, due May 1, 1989	**3,750,000**	125,000
Series E - 7%, due June 15, 1992	**5,775,000**	175,000
Sinking fund debentures:		
$9^3/_4$%, due December 1, 1990	**8,856,000**	356,000
	24,686,000	700,000
Northwestern Utilities Limited:		
First mortgage sinking fund bonds:		
Series F - $4^3/_4$%, due January 15, 1979	**954,000**	238,500
Series G - $5^3/_8$%, due April 15, 1983	**3,904,000**	9,000
Series H - $5^3/_4$%, due March 1, 1988	**7,954,000**	49,000
Series I - $6^1/_2$%, due May 1, 1992	**3,960,000**	130,000
Series J - $9^3/_4$%, due December 15, 1994	**6,714,000**	170,000
Sinking fund debentures:		
Series C - $6^3/_4$%, due May 1, 1977	**524,000**	
Series D - $6^3/_4$%, due December 1, 1978	**572,500**	22,500
Series E - $7^1/_4$%, due October 15, 1985	**3,024,000**	106,000
	27,606,500	725,000
Total long-term debt	**192,645,500**	$11,578,000
Deduct current maturities	**11,578,000**	
Long-term debt less current maturities	**$181,067,500**	

The long-term debt outstanding and current maturities thereof are stated after deducting bonds and debentures which have been purchased by the company and are held for future sinking fund payments and excluding requirements which may be satisfied by certification of property additions.

Installments of long-term debt maturing in each of the calendar years 1976, 1977, 1978, 1979 and 1980 amount to $11,578,000, $4,976,500, $6,453,500, $9,378,500 and $5,900,000 respectively. These maturities exclude requirements which may be satisfied by certificates of property additions and after deducting bonds and debentures which have been repurchased.

The companies have in effect a pension plan covering substantially all their employees. The aggregate unfunded past service liability, being amortized over periods not exceeding 17 years, amounted to approximately $5,932,000 at December 31, 1975.

17. Interim rates

The Public Utilities Board of Alberta has approved interim rate increases under which electric revenues of approximately $4,104,000 and natural gas revenues of approximately $5,093,000 have been recorded as of December 31, 1975. In the event that the interim rate increases approved to date are not fully confirmed, the company will be required to refund the amount of such reduction to its customers.

18. Anti-Inflation Act

The effect of the federal government's anti-inflation program contained in The Anti-Inflation Act and Regulations in respect to dividend payments by companies is to prohibit Canadian Utilities Limited from declaring common dividends in excess of a total amount of 74 cents per share during the first compliance period from October 14, 1975 to October 13, 1976.

19. Subsequent event

The company has entered into an agreement dated January 14, 1976 with underwriters for the sale to them of $50,000,000 principal amount of 11¼% Debentures 1976 Series (unsecured) to mature February 15, 1996 at an aggregate price of $49,125,000. The net proceeds to be received by the company are $49,000,000 after deducting expenses of issue, estimated at $125,000.

Auditors' Report to the Shareholders

We have examined the consolidated balance sheet of Canadian Utilities Limited and subsidiaries as of December 31, 1975 and the consolidated statements of earnings, retained earnings and changes in financial position for the year then ended. Our examination included a general review of the accounting procedures and such tests of accounting records and other supporting evidence as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company and subsidiaries as of December 31, 1975 and the results of their operations and the changes in financial position for the year then ended, in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Peat, Marwick, Mitchell & Co.

Chartered Accountants

Edmonton, Alberta
January 30, 1976

The bond and debenture indentures executed by the company and its subsidiaries place limitations on the company and its subsidiaries, including restrictions on the payment of dividends. Of the consolidated retained earnings at December 31, 1975 and 1974, approximately $28,243,000 and $16,636,000, respectively, were free from such restrictions.

11. Amount received under the Natural Gas Pricing Agreement Act

Under the Natural Gas Pricing Agreement Act, effective November 1, 1975, Alberta gas producers receive a pro-rata share of monies available under the Act. The company has received $478,000 net of royalties and income taxes from the Alberta Government as its share. While it is the intention of the company to utilize these monies for further development and exploration of natural gas fields, such disposition is subject to approval of the Public Utilities Board of Alberta.

12. Minority interests

Northwestern Utilities Limited:		
105,000 4% Cumulative Redeemable Preference Shares of the par value of $100 each		$10,500,000
Canadian Western Natural Gas Company Limited:		
275,410 4% Cumulative Redeemable Preference Shares of the par value of $20 each	**$5,508,200**	
200,000 5-1/2% Cumulative Redeemable Preference Shares of the par value of $20 each	**4,000,000**	9,508,200
		$20,008,200

Preferred shares

Authorized:

40,000 5% Cumulative Redeemable Preferred Shares of the par value of $100 each.

150,000 series preferred shares of the par value of $100 each, issuable in series, of which 15,000 shares have been designated as Cumulative Redeemable Preferred Shares 4-1/4% Series and 50,000 shares designated as Cumulative Redeemable Preferred Shares 6% Series.

4,000,000 series second preferred shares of the par value of $25 each, issuable in series, authorized May 16, 1974, of which 1,200,000 shares have been designated as 10-1/4% Cumulative Redeemable Second Preferred Shares Series A.

1,780,000 $1.25 Cumulative Redeemable Convertible Preferred Shares of the par value of $20 each.

During the year the company issued for cash $30,000,000, 10-1/4% cumulative redeemable second preferred shares Series A. The net proceeds received were $28,973,000, after deducting underwriting commission and expenses of issue.

Issued:	**1975**		1974	
	Number of Shares	**Value of Shares**	Number of Shares	Value of Shares
5% preferred shares (i)	**40,000**	**$ 4,000,000**	40,000	$ 4,000,000
Preferred shares 4-1/4% series (ii)	**15,000**	**1,500,000**	15,000	1,500,000
Preferred shares 6% series (iii)	**50,000**	**5,000,000**	50,000	5,000,000
10-1/4% second preferred Series A (iv)	**1,200,000**	**30,000,000**		
$1.25 convertible preferred shares (v)				
Balance at beginning of year	**1,772,659**	**35,453,180**	1,777,939	35,558,780
Converted at varying dates into common shares without nominal or par value	**(1,511,375)**	**(30,227,500)**	(5,280)	(105,600)
Issued and outstanding	**261,284**	**5,225,680**	1,772,659	35,453,180
		45,725,680		45,953,180
Deduct preferred shares to be redeemed within one year (iv)		**1,200,000**		
Balance at end of year		**$44,525,680**		$45,953,180

(i) Redeemable at the option of the company on thirty days' notice at $104 per share.

(ii) Redeemable at the option of the company on thirty days' notice at $102.50 per share.

(iii) Redeemable at the option of the company on thirty days' notice at $104 per share on or before February 1, 1977, thereafter reducing at various dates to a minimum redemption price of $101 per share.

(iv) Commencing June 1, 1976 the company, through the operation of a cumulative mandatory sinking fund, is required to redeem 48,000 shares per annum at a price of $25 per share plus an amount equal to all dividends accrued and unpaid. Through the operation of a non-cumulative optional sinking fund an additional 36,000 shares may be called for redemption on the same terms. Redemptions for other than sinking fund purposes may be made subsequent to January 31, 1980 and prior to January 31, 1981 at $26.25 per share plus an amount equal to all dividends accrued and unpaid and, thereafter, at various dates and at various amounts reducing to a minimum redemption price of $25 per share.

(v) Non-redeemable up to January 1, 1982 (unless the number of shares outstanding is equal to or less than 75,000), thereafter, redeemable at the option of the company on thirty days' notice at $20 per share. Up to January 15, 1982, convertible into two common shares and thereafter into 1.6 common shares up to January 15, 1992. Each holder of convertible preferred shares is entitled to one vote in respect of each two convertible preferred shares held. The conversion rates are subject to adjustment under certain circumstances.

14. Common shares

Authorized:
30,000,000 without nominal or par value

Issued:

	1975		1974	
	Number of Shares	**Value of Shares**	Number of Shares	Value of Shares
Balance at beginning of year	**10,075,466**	**$ 65,429,512**	10,064,906	$65,323,912
Issued on conversion of $1.25 preferred shares	**3,022,750**	**30,227,500**	10,560	105,600
Issued on exercise of share purchase warrants	**160**	**1,440**		
Issued during the year	**1,100,000**	**10,175,000**		
Balance at end of year	**14,198,376**	**$105,833,452**	10,075,466	$65,429,512

At December 31, 1975 the company has reserved 1,117,568 common shares for issue as follows:

In connection with share purchase warrants out-standing exercisable at a price of $9 per share (price is subject to adjustment in certain circumstances). The warrants expire May 15, 1978	595,000
In connection with the $1.25 cumulative redeemable convertible preferred shares	522,568
	1,117,568

On December 18, 1975 the company sold 1,100,000 common shares without nominal or par value at a price of $9.25 per share, amounting to $10,175,000 in aggregate. The net proceeds received were $9,464,500 after deducting underwriting commission of $610,500 and expenses of issue of $100,000.

15. Remuneration of directors and officers

During the year ended December 31, 1975 the company paid aggregate remuneration of $62,000 to 13 directors as directors ($36,000 to 13 directors in 1974) and $382,000 to eight officers as officers ($308,000 to eight officers in 1974). Two officers were also directors in 1975 and two in 1974.

16. Commitments

The cost of the company's construction and expansion program for 1976 will amount to approximately $78,656,000. Commitments under contract pertaining to this program are approximately $35,200,000 at December 31, 1975, of which approximately $24,588,000 will be incurred in 1976.

Eleven Year Growth Summary

(dollars in thousands except per share data)	1975	1974	1973
Natural Gas Revenues	$ 142,436	$ 91,486	$ 82,066
Electric Revenues	57,945	46,295	38,305
	200,381	137,781	120,371
Operating Expenses			
Natural gas supply	70,852	40,179	35,907
Operating and maintenance	56,541	43,572	34,729
Taxes — other than income	11,804	8,035	6,829
Depreciation	13,293	12,906	11,019
	152,490	104,692	88,484
Operating Income	47,891	33,089	31,887
Other Income			
Interest capitalized during construction	4,022	1,601	785
Interest and dividends	417	223	208
Gain on purchase of long-term debt	405	286	328
Miscellaneous	527	464	253
	5,371	2,574	1,574
	53,262	35,663	33,461
Income Deductions			
Interest on long-term debt	15,446	13,902	11,931
Interest on loans to parent and affiliated companies	263	262	371
Other interest	3,852	2,691	1,153
Debt discount and expense amortized	290	272	235
	19,851	17,127	13,690
	33,411	18,536	19,771
Income Taxes	8,686	2,416	4,536
	24,725	16,120	15,235
Minority Interests	860	860	860
Net Earnings Before Extraordinary Items	23,865	15,260	14,375
Extraordinary Items — Non-Recurring Gain (Loss)	2,329	444	
Net Earnings	26,194	15,704	14,375
Preferred Dividends	5,075	2,781	2,787
Net Income to Common Shareholders	21,119	12,923	11,588
Common Shares Outstanding	14,198,376	10,075,466	10,064,906
Earnings — Dollars Per Common Share (reflecting 4-for-1 share split September 25, 1972)			
Basic			
Net earnings before extraordinary items	1.69	1.24	1.15
Net earnings	1.90	1.28	1.15
Fully Diluted			
Net earnings before extraordinary items	1.45	1.05	.99
Net earnings	1.61	1.08	.99
Common Dividends Paid (Not applicable prior to 1972)			
Amount	7,142	5,943	5,535
Dividends Per Share	.65	.59	.55
Electric Statistics			
Gross plant in service at cost	309,345	260,743	218,202
Accumulated depreciation	45,677	41,246	35,954
Capital additions	51,288	45,021	21,377
Sales (thousands of kilowatt hours)	2,024,713	1,920,408	1,782,908
Maximum demand (thousands of kilowatts)	445	388	376
Plant capacity (thousands of kilowatts)	686	523	512
Customers at year-end	94,040	88,822	84,598
Communities served	365	364	365
Miles of power lines	12,004	11,710	11,245
Average annual use per residential customer (kilowatt hours)	6,774	6,369	6,069
Gas Statistics			
Gross plant in service at cost	304,287	277,922	252,106
Accumulated depreciation	89,365	83,945	78,593
Capital additions	29,893	26,963	16,611
Sales (millions of cubic feet)	254,577	241,949	240,462
Maximum daily demand (millions of cubic feet)	1,318	1,210	1,092
Customers at year-end	373,254	353,331	335,494
Communities served	253	253	253
Miles of pipe lines	11,797	10,489	9,837
Average annual use per residential customer (cubic feet)	212,358	208,376	212,300

1972	1971	1970	1969	1968	1967	1966	1965
$ 78,875	$ 70,342	$ 62,972	$ 59,221	$ 53,809	$ 51,925	$ 50,594	$ 48,255
33,849	30,552	27,666	21,968	18,830	16,725	15,068	13,959
112,724	100,894	90,638	81,189	72,639	68,650	65,662	62,214
32,357	26,982	22,695	21,330	19,766	19,381	18,086	15,536
33,389	29,103	26,365	23,812	20,606	18,615	17,163	16,210
6,516	5,959	5,288	4,755	4,366	4,076	3,902	3,617
10,134	9,716	9,378	7,921	7,134	6,845	6,361	5,926
82,396	71,760	63,726	57,818	51,872	48,917	45,512	41,289
30,328	29,434	26,912	23,371	20,767	19,733	20,150	20,925
2,170	774	194	1,091	939	383	156	70
466	704	480	336	584	665	294	478
36	379	179	66	197	52	72	57
306	243	16	202	115	67	88	48
2,978	2,100	869	1,695	1,835	1,167	610	653
33,306	31,234	27,781	25,066	22,602	20,900	20,760	21,578
11,033	8,804	6,870	6,116	5,785	4,825	4,037	3,705
459	263	372	375	47			68
438	708	1,698	993	581	305	199	258
229	206	168	154	147	122	104	103
12,159	9,981	9,108	7,638	6,560	5,252	4,340	4,134
21,147	21,253	18,673	17,428	16,042	15,648	16,420	17,444
5,054	7,132	6,912	5,705	5,152	5,954	6,860	7,559
16,093	14,121	11,761	11,723	10,890	9,694	9,560	9,885
962	1,226	1,160	1,167	1,149	1,138	1,156	1,168
15,131	12,895	10,601	10,556	9,741	8,556	8,404	8,717
(89)	183	234	2,888	207	14	256	647
15,042	13,078	10,835	13,444	9,948	8,570	8,660	9,364
2,766	2,514	2,514	2,514	2,514	2,415	2,214	2,214
12,276	10,564	8,321	10,930	7,434	6,155	6,446	7,150
10,062,646	10,056,024	8,948,528	8,873,752	8,873,672	8,860,860	8,838,608	8,792,524
123	103	90	91	81	69	70	74
122	105	93	123	84	69	73	81
1.05	.91	.80	.81	.74	.67	.68	.71
1.04	.93	.82	1.03	.76	.67	.70	.76
5,231							
.52							
198,165	175,477	147,521	132,294	118,556	94,189	77,813	67,998
31,814	28,337	24,568	21,084	18,901	17,093	15,478	13,917
24,719	29,023	16,293	15,150	26,225	17,899	11,149	7,885
1,520,031	1,274,649	1,118,239	967,276	769,501	645,283	563,112	562,267
342	295	281	245	216	178	149	135
370	367	367	344	197	197	193	172
80,492	77,246	74,193	72,042	70,076	67,503	65,487	63,599
365	359	355	343	342	342	340	314
10,823	9,951	9,715	9,197	8,497	7,602	7,205	6,456
5,961	5,550	5,209	5,127	4,617	4,306	4,054	3,884
237,682	221,757	211,894	200,721	190,024	181,545	172,946	164,691
73,760	68,854	64,038	59,289	55,032	51,050	47,152	43,367
16,879	10,876	12,280	11,803	9,674	9,190	9,080	8,435
231,995	206,618	186,812	173,030	153,055	150,402	143,195	135,291
1,106	1,090	986	904	918	784	752	714
317,766	303,253	289,457	278,412	266,669	255,332	247,157	239,390
251	249	240	238	229	221	206	195
9,439	9,166	8,753	8,106	7,328	6,410	5,689	5,508
230,000	217,800	217,000	222,600	210,900	209,000	222,100	226,300

Alberta — A Climate for Growth

CU's prospects are inseparably linked for the foreseeable future to the economic performance of the province of Alberta. Judging by the province's performance of the past five years, the company has reason to be optimistic.

Alberta's real economic growth during most of this period has exceeded that of Canada as a whole. Table I at right compares the gross domestic products of Alberta and Canada from 1970 to 1974.

In the same period, capital investment in Alberta (Table II) has advanced at an annual compound growth rate of 16.1 per cent. A particularly significant gain— 33 per cent — is estimated for the past year in the utilities sector.

Much of the impetus for capital spending comes from natural resource extraction and upgrading projects such as the Syncrude and Great Canadian Oil Sands developments, and the world-scale petrochemical complex approved by the Alberta government in September.

During 1975 the Alberta Department of Industry and Commerce assembled a list of 37 projects in the planning stages in the province, representing an estimated $7.5 billion in total investment. At the same time the department identified another 76 projects actually underway valued at $3.1 billion.

Incentive programs introduced by the provincial government, together with higher natural gas prices negotiated with Ottawa during the year, are attracting large investments in oil and gas exploration programs.

Looking ahead, the Alberta government's basic economic goal is diversification and less dependence on the sale of unprocessed, non-renewable resources. To date the focus has been largely on petrochemicals with more than $1 billion worth of new plant in the planning stages. In this connection, CU is planning a joint venture with Dome Petroleum to build and operate a 20,000 barrel-a-day ethane extraction plant in Edmonton.

The provincial government is also keenly aware of the potential of its vast coal deposits. The Alberta Research Council, in cooperation with other research institutes in Canada and abroad, is seeking to unravel the technological and economic problems associated with coal gasification. Gas produced from coal could eventually help supplement Canada's depleting natural gas supplies. Also, plentiful coal reserves assure a long-term supply of low-cost fuel for the generation of electric power.

Another major goal of the Alberta government is to distribute economic growth throughout the province rather than allow it to concentrate in the Edmonton and Calgary areas. The long-term goal of this policy is to have 15 or 20 cities of about 40,000 in population by the year 2000. As an initial step in encouraging this development, the provincial government is re-locating a number of departments and agencies from Edmonton to smaller communities. A significant portion of this decentralization is to take place in rural areas of eastern Alberta served by Alberta Power.

In summary, Alberta's growth and diversification means burgeoning demand for CU's utility services, and promising new opportunities for the company to share in and contribute to the province's continuing economic upsurge.

TABLE I: ALBERTA'S ECONOMIC PERFORMANCE
Comparison of Gross Domestic Product* Alberta and Canada ($ Million)

	G.D.P.		% Change in G.D.P.	
	Alberta	Canada	Alberta	Canada
1970	6,782	87,071	7.9	7.4
1971	7,349	94,883	8.4	9.0
1972	8,105	105,073	11.5	10.7
1973	10,175	120,736	24.2	14.9
1974	12,046	141,726	18.4	17.4

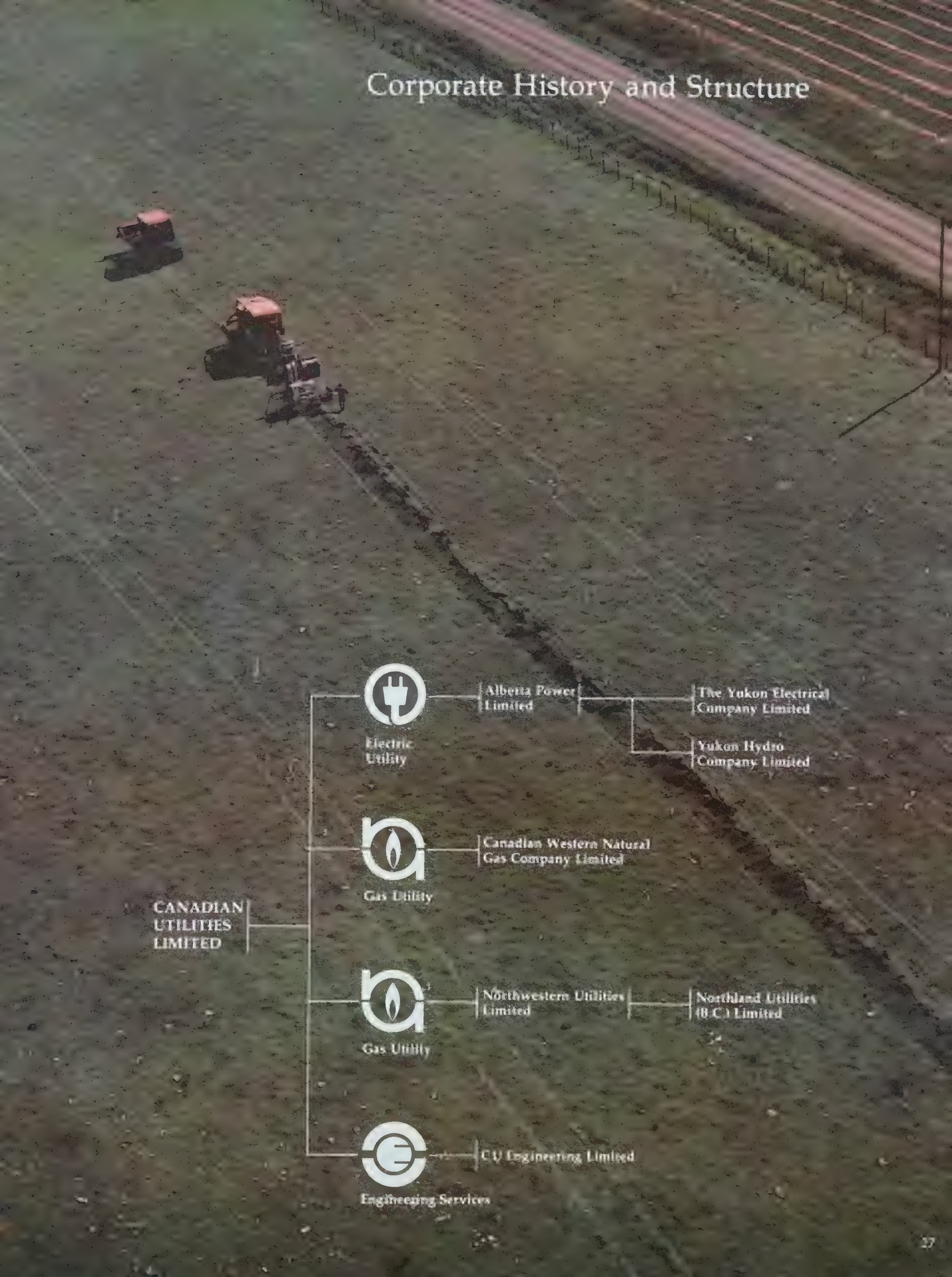
* Gross Domestic Product measures actual productive performance. It does not include income that accrues to residents of the province or nation from outside the province or nation, and does not include payments to individuals or companies residing outside the province or nation.

TABLE II: PRIVATE & PUBLIC INVESTMENTS IN ALBERTA ($ Million)

	1970	1971	1972	1973	1974	**Est. 1975**	**5 Year % C.G.R.**
Primary Industries and Construction	878	946	1007	1253	1633	**2038**	**18.3%**
Manufacturing	184	187	246	394	409	**414**	**17.7%**
Utilities	496	472	501	557	763	**1016**	**15.4%**
Trade, Finance & Commercial Services	187	180	280	404	432	**425**	**17.9%**
Housing	350	492	538	588	701	**680**	**14.2%**
Institutional Services & Government Departments	392	442	426	472	566	**672**	**11.3%**
TOTAL	2487	2719	2998	3668	4504	**5245**	**16.1%**

The development of plastic pipe for rural gas distribution lines has made possible the extension of modern gas service to vast areas of rural Alberta. Bulldozers in tandem plow in the plastic pipe across a field in central Alberta.

Corporate History and Structure



- CANADIAN UTILITIES LIMITED
  - Electric Utility — Alberta Power Limited
    - The Yukon Electrical Company Limited
    - Yukon Hydro Company Limited
  - Gas Utility — Canadian Western Natural Gas Company Limited
  - Gas Utility — Northwestern Utilities Limited
    - Northland Utilities (B.C.) Limited
  - Engineering Services — CU Engineering Limited

Canadian Utilities Limited

Canadian Utilities Limited, previously an operating electric utility, has now completed its fourth year of operation as a holding company and parent of three of Alberta's major electric and natural gas utilities. Another subsidiary, CU Engineering Limited, was created in 1975 to market the organization's expertise in design engineering, project management and system and capacity evaluation for natural gas and electric distribution and transmission systems.

Alberta Power Limited, formerly called Canadian Utilities Limited, generates, transmits and distributes electric power principally in Alberta and to a lesser extent in the Northwest Territories. Through its subsidiaries The Yukon Electrical Company Limited and Yukon Hydro Company Limited, it serves the Yukon Territory.

Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited produce, transmit and distribute natural gas to most of the major cities and towns, and many rural areas of Alberta. Northwestern also provides natural gas service to Dawson Creek, B.C. through its subsidiary, Northland Utilities (B.C.) Limited.

Alberta Power Limited

The history of Alberta Power dates back to 1926 when Vegreville Utilities Limited was incorporated. In 1927 Mid-West Utilities Limited was formed under a Dominion charter and assumed the operation of Vegreville and other properties in Alberta and Saskatchewan. The company's name was changed to Canadian Utilities Limited in 1928, and to Alberta Power Limited in 1972.

As the company expanded, diesel plants were installed in many communities and 24-hour service was instituted at reduced rates. In 1929 the company built and operated the first mobile rail car generating plant in Canada for emergency service in Saskatchewan and Alberta. Among systems acquired was that of Union Power Company Limited at Drumheller, which was amalgamated with Canadian Utilities Limited in 1935. In 1944 the company connected the first electrified oil well in Western Canada. In 1965 the first truck-trailer mobile generating stations in Alberta were built by the company to supply power to the rapidly developing oil fields on a short-term basis. At that time 40 per cent of the company's load was associated with the oil and gas industry.

In 1944 rural electrification was initiated on an experimental basis to an area of farms in the Swalwell district. Today there are 20,415 farm customers in the company's service area.

All of the company's Saskatchewan properties, except those in and adjacent to Lloydminster, were nationalized by the Saskatchewan government in 1947, reducing the company to about half its former size.

The company then embarked on a vigorous expansion program in Alberta. A gas-fired steam plant was built at Vermilion using turbines and boilers acquired from old U.S. naval vessels. In 1954 Canada's first gas turbine generator was put into operation at Vermilion, while a coal-fired plant was built on the Battle River in east-central Alberta adjacent to the vast coal fields near Forestburg. In 1975 at Battle River a fourth generating unit of 150,000 kilowatts was commissioned, bringing total capacity of the plant to 366,000 kilowatts.

In 1973 the H.R. Milner generating plant was commissioned at Grande Cache with a capacity of 150,000 kilowatts. The plant bears the name of the late honorary chairman of Canadian Utilities, who played a commanding role in the early development of the company's electric operations.

The Yukon Electrical Company Limited and Yukon Hydro Company Limited were purchased in 1958. Yukon Electrical now supplies service to 18 communities.

Canadian Western Natural Gas Company Limited

Canadian Western, the oldest of the utility companies and a pioneer in the natural gas industry, was incorporated in 1911 following the discovery of the Bow Island field in southern Alberta.

In 1912 the company built a 170-mile, 16-inch transmission line from the Bow Island field to Lethbridge and Calgary, with connections to other communities.

Bow Island continued to be the main source of supply until 1922 when the Turner Valley field was connected to

Canadian Western's system. Today, however, the major part of the company's annual supply comes from the Jumping Pound - Jumping Pound West and Sarcee fields. Gas was first supplied from these areas in 1951. In 1958 the company developed the Carbon field which, along with the Bow Island and Foremost fields, is now used to meet peak demands for natural gas. Bow Island has been used as a storage field since 1930. In addition to these sources, purchases of gas are made from other producers, notably in the Okotoks and Redland-Strathmore fields. Several communities which are isolated from Canadian Western's main transmission line are served from the Alberta Gas Trunk Line system.

Canadian Western serves many industrial consumers among the largest of which are fertilizer plants, including one in Medicine Hat connected in 1975, cement and lime plants, oil refineries and sugar beet factories. Since 1966, when Canadian Western pioneered the technique of plowing plastic pipe, the company has developed an extensive rural gas system in southern Alberta. Service was extended to three major rural areas in 1974: Buffalo Gas Co-op near Brocket, Willow Creek Co-op near Claresholm and Bow North Co-op near Calgary.

The principal markets are the cities of Calgary and Lethbridge. In total the company today serves 101 communities in southern Alberta.

Northwestern Utilities Limited

Northwestern Utilities Limited, a fully integrated natural gas utility company formed in 1923, produces, purchases, transmits and distributes natural gas in north central and northern Alberta.

From the start of the company's operations in 1923 until the end of 1949, all supplies of natural gas came from company wells in the Viking-Kinsella field 80 miles east of Edmonton. The field produces "sweet" dry gas and is still an important source of supply to the company, even though there are a number of other sources now connected to the system. The company at present owns and operates 145 wells, located mainly in four major gas fields in the province.

Natural gas service is also provided to Dawson Creek, B.C. through a subsidiary, Northland Utilities (B.C.) Limited.

The first major expansion in market area took place in 1946 when a transmission line was built connecting the Viking-Edmonton line to the City of Red Deer. The communities of Camrose, Wetaskiwin, Ponoka and Lacombe were connected along the way. New communities were added steadily, and in 1972 Northwestern acquired all the gas operations of its affiliate, Northland Utilities Limited, taking over service to 15,360 customers in 36 northern Alberta centres including Grande Prairie. At that time Northland went into voluntary liquidation.

Today Northwestern Utilities serves 153 communities. The company's largest customer is the City of Edmonton whose citizens rely on natural gas, not only for heating, but also for electricity supplied by gas-fueled plants of Edmonton Power. Other large customers include power plants of Calgary Power and Alberta Power, fertilizer, cement and chemical plants, and oil refineries in the Edmonton area.

During 1974 and 1975, Northwestern installed 49 miles of 24-inch diameter transmission line between the Alberta Gas Trunk Line system at Homeglen-Rimbey and Northwestern's facilities at Edmonton.

Gas meters are loaded at Canadian Western's service centre in Calgary.

Board of Directors

G. L. Crawford, Q.C.
Barrister & Solicitor
McLaws & Company
Calgary, Alberta.

W. D. H. Gardiner
Deputy Chairman and
Executive Vice-President
The Royal Bank of Canada
Toronto, Ontario.

[1] **F. T. Jenner**
Company Director
Edmonton, Alberta.

E. W. King
President
Canadian Utilities Limited
Edmonton, Alberta.

P. L. P. Macdonnell, Q.C.
Barrister and Solicitor
Milner & Steer
Edmonton, Alberta.

J. E. Maybin
Chairman and Chief Executive Officer
Canadian Utilities Limited
Toronto, Ontario.

[1] **D. R. B. McArthur**
Chairman of the Board
Inland Cement Industries Ltd.
Edmonton, Alberta.

[1] **W. S. McGregor**
President
Numac Oil & Gas Ltd.
Edmonton, Alberta.

W. S. McLeese
President
Trans Canada Freezers Limited
Toronto, Ontario.

J. M. Seabrook
Chairman and President
IU International Corporation
Salem, New Jersey, U.S.A.

[2] **D. K. Yorath**
Vice-Chairman
IU International Corporation
Edmonton, Alberta.

[1] Member of audit committee

[2] Dr. Yorath will not be standing for re-election at the annual meeting on April 23, 1976.

Honorary Director

F. C. Manning
Company Director
Calgary, Alberta.

Senior Officers

J. E. Maybin
Chairman and Chief Executive Officer

[3] **E. W. King**
President

K. A. Biggs
Senior Vice-President - Finance

Canadian Utilities Staff Executives

D. R. Brandt
Vice-President

A. M. Anderson
Treasurer

H. N. Bottomley
Controller

W. A. Sullivan
Secretary

Harry Brown
Assistant Secretary and
Assistant Treasurer

Edith M. Slipper
Assistant Secretary

[3] E. W. King is also president and chief executive officer of the subsidiary companies: Alberta Power Limited, Canadian Western Natural Gas Company Limited, Northwestern Utilities Limited and CU Engineering Limited.

Subsidiary Company Executives

Alberta Power Limited

W. G. Sterling
Senior Vice-President

R. H. Choate
Vice-President

Keith Provost
Vice-President

Canadian Western Natural Gas Company Limited
Northwestern Utilities Limited

J. H. Pletcher
Senior Vice-President

D. L. Weiss
Vice-President
Gas Supply

A. J. L. Fisher
Vice-President and General Manager
Canadian Western Natural Gas
Company Limited

B. M. Dafoe
Vice-President and General Manager
Northwestern Utilities Limited

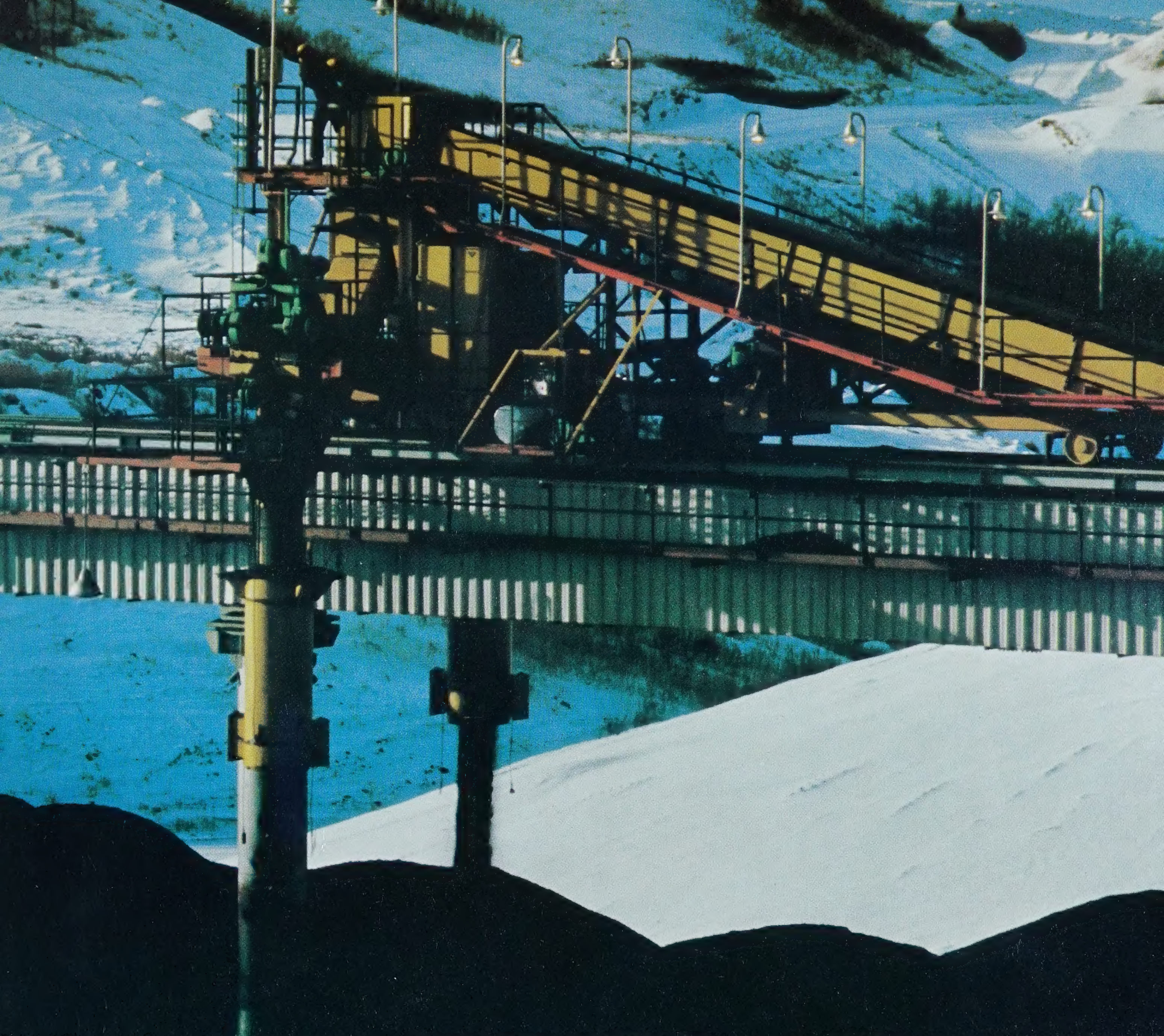
Inter-Company

D. B. Mitchell
Vice-President - Industrial Relations

CU Engineering Limited

D. M. Murray
General Manager

At right is a section of the Battle River generating station's coal conveyor system. This station, including the newly completed Unit Number Four, consumes about 5,000 pounds of coal a day during full operation. The coal is pulverized to the consistency of flour for proper combustion.



Subsidiary Companies

Alberta Power Limited
and subsidiaries:
- The Yukon Electrical Company Limited
- Yukon Hydro Company Limited

Canadian Western Natural Gas
Company Limited

CU Engineering Limited

Northwestern Utilities Limited
and subsidiary:
- Northland Utilities (B.C.) Limited

Registered Head Office: 10040 - 104 Street
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Telephone: (403) 424-6161

Toronto Office
2314 Commercial Union Tower
Toronto Dominion Centre
Toronto, Ontario, Canada M5K 1H1
Telephone: (416) 869-3868

Transfer Agent and Registrar

Common Shares and Preferred Shares
Montreal Trust Company:
Montreal/Toronto/Winnipeg/Regina
Calgary/Edmonton/Vancouver

Stock Exchange Listings

Common Shares:
Toronto and Montreal Stock Exchanges

Preferred Shares:
$1.25 Convertible Preferred
10¼% Series Second Preferred

Toronto and Montreal Stock Exchanges

5% Preferred
4¼% Series Preferred
6% Series Preferred

Toronto Stock Exchange

Auditors

Peat, Marwick, Mitchell & Co.
2500 Alberta Telephone Tower
10020 - 100th Street,
Edmonton, Alberta.

Annual Meeting

The annual meeting of shareholders will be held in Edmonton on April 23, 1976.




CANADIAN UTILITIES LIMITED